Reliability Contracts Between Renewable and Natural Gas Power Producers

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Abstract—Renewable power adoption has required policies that protect intermittent generators, such as wind and solar, from system-level costs of resource shortfalls. It has been shown that if renewable generators were to accommodate these costs in energy market settlement, significant renewable generation curtailments would ensue, especially as the penetration of renewables grows. Based on the current evolution of policies towards unmet commitment penalties for intermittent generators, we propose a reliability contract between a renewable power producer (RPP) and a natural gas power plant (NGPP) where the NGPP fulfills the RPP unmet commitments in low resource scenarios. We consider a day-ahead energy market where players are scheduled based on quantity-price bids in a least-cost manner by an Independent System Operator (ISO). We analyze the contract against a baseline scenario where the RPP faces the shortfall penalty, deriving optimal commitments and a condition where the adoption of the reliability contract increases social welfare. Using data from a RPP-NGPP pair in Northeastern United States, the contract is shown to improve renewable utilization, increase the profits of both partners, and decrease total unmet commitments through the introduction of a lower-cost alternative to the shortfall penalty.

I. INTRODUCTION

THE decarbonization of energy systems has resulted in widespread adoption of policies that favor the integration of renewable generation such as wind and solar power. In the United States, these policies, by and large, have included the treatment of renewables as non-dispatchable generators, largely allowing them to self-schedule as a negative load and exempting them from under-generation penalties [1]. As renewable penetration increases, the costs associated with integrating renewables cannot be disregarded and need to be included in the costs faced by renewable power producers. Broadly speaking, integration of renewable generation is more expensive than conventional generation to system operators and other generators due to resource volatility.

System operators need to set reserve requirements not only by quantifying low probability unscheduled maintenance and running contingency analyses of their traditional network but by assessing the higher probability generation shortfalls of renewable power producers with respect to forecasts and commitments [2]. Additionally, deviations from day-ahead and real-time energy market commitments place an additional stress on other power plants, that must also deviate from their commitments to fulfill demand. These costs are thought to be higher than the day-ahead or real-time marginal energy price and motivate a penalty settlement of renewable generation deviations [3]. For this reason, system operators with increasingly large amounts of renewable penetration are beginning to adopt policies where generators face real-time costs and add-on penalties when unable to meet power commitments set through a market. PJM and BPA in the US [4] are examples of the introduction of such policies. Previous work has shown, in fact, that these penalties decrease renewable utilization [5], as generators bid more conservatively than in policy scenarios with lower or nonexistent penalties.

In this paper, we propose a reliability contract between a renewable power producer (RPP) and a fast-ramping natural gas power plant (NGPP) that improves the utilization of renewable generation. Our aim is to show that with such a contract, any unmet commitments of the RPP are fulfilled by the NGPP at a lower cost than the shortfall penalty. Such a shortfall payment reduction allows the RPP to offer more capacity, thereby leading to a better utilization of the RPP. This in turn helps the RPP to be treated as more of a dispatchable asset rather than a negative load, leading to better grid reliability.

We consider that these power producers participate in a day-ahead (DA) market alongside a third type of power producer, a conventional power plant (CPP) that may correspond, for instance, to a slow-ramping thermal unit. The generators participate in the DA market by submitting price-quantity bids to an independent system operator (ISO) that clears the market in least-cost fashion, determining hourly schedules for each market participant. We assume that the NGPP and CPP are able to fulfill their hourly commitments and that the RPP faces the uncertainty of its resource. Any real-time power output that exceeds the commitment is curtailed and any real-time shortfall is penalized. Using this model, we carry out a comparison in this paper with a baseline scenario with no contract between the RPP and the NGPP against one with a reliability contract.

The main contributions of this paper are two-fold: first, it introduces the design and analysis of a contract between a renewable and a natural gas power producer, deriving optimal commitments and a condition for social welfare increase; second, it illustrates increased renewable utilization, decreased unmet commitments and increased profits for each contract participant with respect to the baseline scenario through simulation of the described market and contract.

There are many directions of research relevant to the work

here that have been carried out in the literature. The work on grid costs of renewable intermittence is extensive; the reader is referred to [6] and references therein. Boundaries of firms have been explored in the economics literature (ex. seminal works such as [7], [8], [9] among others). Other groups have proposed partnering renewable power producers with dispatchable generators such as hydropower, which is specifically studied by [10] and [11]. In many of these papers, the hydro resource is assumed to function as a storage device operated by the renewable player. Rather than studying partnerships that require such an integrated operation, we have assumed in this paper that the natural gas power plant owner and the renewable producer are individual players, each with their own utility function. The fast-ramping, low relative emission and low fuel cost of NGPPs make them an ideal complement for managing renewable volatility.

The literature on the use of storage to mitigate the intermittence of renewables (see, e.g., [12], [13]) is relevant. While these works have so far largely assumed that these storage options are owned and operated by a centralized source, one can envisage designing similar bilateral contracts as considered in this paper between renewables and storage owners as well. Some works have also considered using NGPPs to firm up renewable supply. In particular, we can point to works such as [14], [15] that assumes that the renewable and the NGPP *jointly* optimize their decisions, [16] that studies impact on natural gas prices due to volatility from renewable production in the power grid, [17] that studies the equilibrium of coupled gas and electricity markets, and [18] that relates the uncertainties of natural gas-fired generation due to fuel constraints and the cost of electricity. More general issues arising from the interdependency of the natural gas and the electricity infrastructures have also been considered, e.g., see [19], [20].

The studies presented in [21] are the most relevant to this work. They propose a bilateral contract between a RPP and a NGPP, in which the NGPP reserves some amount of fuel to be used in the event of a renewable resource shortage. Unlike their approach, our model does not require the NGPP to purchase a fuel reserve ex-ante. Instead, the reliability contract proposed in this paper allows the NGPP to procure natural gas in real time, as the renewable production is realized and shortages become known. Although this comes at the expense of mathematical tractability, it allows for a decrease in the fuel cost, since the NGPP will only purchase the amount needed for production, thus decreasing the amount of unused gas. Furthermore, we propose that any remaining penalties due to renewable shortage are transferred to the NGPP player, which incentivizes the RPP player to submit higher bids and appropriately reduces the NGPPs commitments in the DA market based on the risk of shortfalls. In our simulations, real data is used to validate our model for a set of players that could engage in a reliability contract that would increase their profit.

On the topic of natural gas procurement, we realize that the proposed real-time adjustment of natural gas by the NGPP player is a departure from current natural gas market operations. Although FERC order 809 improves the integration of electricity and natural gas operations by delaying the Timely

nomination cycle by an hour and a half and introducing a third intraday nomination cycle [22], NGPPs still heavily rely on ad-hoc bilateral trading to access the market. Our work considers renewable generation as the only stochastic input to the system and does not factor in costs associated with fuel shortages and unscheduled maintenance. The adoption of a gas balancing market as described in [23] may enable better coordination of the two systems and allow for the incorporation of reliability contracts with an improved understanding of the NGPP gas procurement costs.

The paper is organized as follows. Section II characterizes the electricity market design considered. It also introduces the utility functions for the three types of market participants for a baseline scenario as well as the utility function modifications under the RPP-NGPP reliability contract. Section III describes the main analytical results, which include the optimal bidding strategies of the market participants, selection criterion for a profitable RPP-NGPP contract and social welfare implications. Section IV describes simulations of the contract using resource and pricing data for a RPP and NGPP pair in Maine. Section V states the main conclusions of our work and potential extensions to our model.

II. Electricity Market Description

This section describes the overall electricity market structure and assumptions in Section II-A which are then used to define the utility functions for the baseline scenario (where no contract exists between the RPP and the NGPP) in Section II-B. We then introduce the reliability contract in Section II-C, and provide modified expressions for the players' utility functions under contract. The market design and utility functions established in this section will be used to derive optimal commitments in the following section.

A. Electricity Market Structure and Assumptions

We consider a two-settlement electricity market, composed of a Day-Ahead energy market (DA market) followed by a settlement mechanism for imbalances between the DA commitments and the actual power output of the generating sources. The typical process in a DA market begins with the various power producers submitting bids to an Independent System Operator (ISO), primarily tasked with meeting the demand reliably through competitive and efficient markets [24]. These bids include a quantity and price for each hour interval of the following day. The ISO clears the DA market by sorting the price-quantity bids by increasing cost, establishing a supply curve. The equilibrium quantity and price are determined by calculating the crossing point between the supply curve and a deterministic demand curve. The crossing point price corresponds to the minimum possible cost to the consumers for the given demand level. Additionally, this methodology sets the energy supply equal to energy demand by construction.

In order to further our analysis of the decisions available to the market players, we make the following simplifying assumptions:

Assumption 1. *The total electrical demand or load, L, is known to the ISO.*
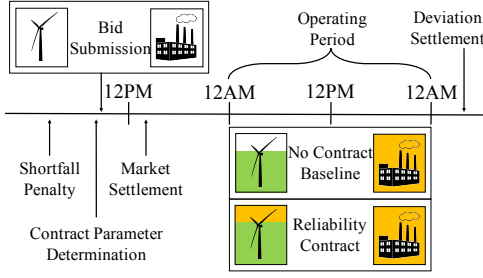
Fig. 1. Timeline for bid submission and market settlement under the no contract baseline and the reliability contract. The cleared, day-ahead commitment of each player is shown in the black rectangles, whereas the real-time operation is shown by the shaded regions on the bottom right of the illustration.

In practice the ISO faces load uncertainty in the day-ahead time horizon and bases commitment clearing decisions with respect to forecasts of load, intermittent generation and contingency analyses [25].

With respect to the time horizon of the DA market operation, we make the following assumption:

Assumption 2. *Electrical demand is met at intervals, $i = 1, \ldots, 24$, disregarding ramp constraints between intervals to establish an hourly day-ahead schedule for the power plants.*

Bids in the DA market are due 13 hours prior to the first operating period, corresponding to 11am of the day prior. The ISO reveals the generator schedules within a few hours of the bid submission as illustrated in Fig. 1.

The market is populated with three types of power plants, a renewable power producer (RPP, r), a natural gas power plant (NGPP, n) and a conventional power plant (CPP, c).

Assumption 3. *The bid prices of the power plants are equal to their marginal costs.*

The RPP, NGPP and CPP submit commitments C_r^*, C_n^* and C_c^* respectively, which are the profit maximizing quantities that solve the utility maximization problem which will be described in Section II-C. The equilibrium commitments are found to be increasing with the DA market price, λ_{DA}, and are discussed in detail in Section III-A. The dependence of optimal commitments with DA market prices is in practice another source of uncertainty for the players, as they are typically required to submit commitment bids before knowing the market equilibrium price. For simplicity, we have not included expectations for each mention of the DA market price although the players will make decisions based on the expectation of λ_{DA}, disregarding price effects. By assuming the power plants bid their marginal costs we assume they are price-takers in the DA energy market.

We note that λ_{DA} is the equilibrium price paid to all of the inframarginal generators (as is typically done in energy markets) and can be described by a piecewise linear function which takes on the discrete bids of the market participants over their specified commitment quantities. Cleared commitments are financially binding, creating an incentive for the generators to meet their submitted quantities.

Assumption 4. *The fossil-fired generators always meet their commitments.*

In other words, we do not consider fuel shortage challenges nor unplanned maintenance for the NGPP and the CPP. As discussed in Section I, we do not consider costs associated with real-time gas procurement. The fossil-based power plants can only produce between a feasible operating regime, set by $P_{n,min}$ and $P_{n,max}$ for the NGPP and $P_{c,min}$ and $P_{c,max}$ for the CPP.

The RPP's real-time power generation, on the other hand, depends on a stochastic resource, such as the wind or the sun. This is the only source of stochasticity in our model and is modeled as a random variable denoted by R.

Assumption 5. *R is a random variable with a twice differentiable, continuous probability density function $f_R(r)$ and cumulative density function $F_R(r)$.*

Given that the RPP's real time power output R, might not be equal to the day-ahead commitment C_r^*, we characterize the market integration of the renewable player as follows:

Assumption 6. *Any excess renewable generation is curtailed. Shortfalls, defined as $S_r = max\{0, C_r - R\}$, are penalized at λ_P, which varies with day-ahead market prices following the relationship $\lambda_P = \alpha\lambda_{DA}$ for $\alpha \geq 1$.*

Although $f_R(r)$ is greater than or equal to zero throughout the interval $[0, P_{r,max}]$, the realized power generation of the RPP lies within $[0, C_r]$.

As mentioned in the introduction, curtailment of RPPs is beginning to be introduced in the US [4] and in Europe at present. The value of λ_P is neither fixed, nor necessarily greater than the marginal cost of any of the players; however, an estimate is known to the market participants prior to bid submission. For simplicity of notation, expectation notation is not used for the parameter α.

Lastly, the costs associated with variable operation and maintenance for the three market participants are given by μ_r, μ_n and μ_c.

B. Baseline Scenario

Based on the market structure defined in Section II-A, we define the utility functions for the three market players when no reliability contract between the RPP and NGPP is in place. This corresponds to our baseline scenario B, representative of current operation of the DA market under shortfall penalties. The RPP's utility function in the baseline scenario u_r^B is dependent on the commitment of the RPP C_r^B, and the DA market price λ_{DA}, and is given by

$$u_r^B(C_r^B, \lambda_{DA}) = \lambda_{DA}C_r^B - \mu_r C_r^B - E_R[\lambda_P S_r^B] \quad (1)$$

where $\lambda_{DA}C_r^B$ is the contribution of the day-ahead energy market income, $\mu_r C_r^B$ is the operation and maintenance costs incurred by the RPP, and $E_R[\lambda_P S_r^B]$ is the expected penalty payment for shortfalls S_r^B. The expected shortfall is taken over the renewable production R. The NGPP's utility function u_n^B is given by

$$u_n^B(C_n^B, \lambda_{DA}) = \lambda_{DA}C_n^B - \mu_n C_n^B - F_n(C_n^B) \quad (2)$$

where $\lambda_{DA} C_n^B$ is the day-ahead energy market income, and $\mu_n C_n^B$ is the operation and maintenance cost. We do not include a shortfall penalty payment given that the NGPP always meets its commitment (Assumption 4). We introduce the fuel payment function F_n which maps a commitment in units of power C_n^B to a fuel cost in dollars.

The fuel cost is no different than a fuel input-power output curve for the generation unit. These functions are developed in practice by fitting models to data collected from operational power plants. A common model in the literature fits a second order polynomial as described in [26]. For the NGPP, fuel costs are modeled as

$$F_n(P_n) = a + bP_n + cP_n^2 \tag{3}$$

where a is a parameter denoting a positive fuel value that adjusts for the no-load costs of the power plant and b and c specify the marginal fuel cost and adjustment for changes in efficiency at different operating points, respectively. Fuel cost functions are monotonically increasing across the operating regime of the power plant as they relate a total power output to a total fuel cost. Combined and single cycle NGPPs have increasing efficiencies across their operating regimes. Increasing efficiency across part-load operation yields concave input-output curves. Because of this reason, c is rarely set to a negative value when used in optimization [27]. Because our proposed contract structure closely reflects the NGPP's part-load operation, in practice, we model fuel costs for the NGPP with increasing efficiency across the operating regime. For the second order polynomial introduced in (3), we therefore set b as positive and c as negative, following the condition on positive marginal fuel cost:

$$0 \leq P_{n,min} \leq P_{n,max} \leq \frac{-b}{2c}. \tag{4}$$

The utility function for conventional power plants includes similar terms:

$$u_c^B(C_c^B, \lambda_{DA}) = \lambda_{DA} C_c^B - \mu_c C_c^B - F_c(C_c^B). \tag{5}$$

Additionally, CPP fuel costs can be expressed with a similar second-order polynomial, as given by

$$F_c(P_c) = d + eP_c + fP_c^2. \tag{6}$$

In practice, conventional steam cycle thermal generators such as coal power plants exhibit decreasing efficiencies across their operating regime, yielding convex fuel cost functions that aid optimization. For this reason, we choose to model the CPP's fuel cost function with a positive f.

The utility functions for the baseline, no reliability contract scenario, are therefore given by (1), (2) and (5) for the three players.

C. Reliability Contract

Having defined the baseline market conditions in Sections II-A and II-B we now introduce the reliability contract (RC) between the RPP and the NGPP which constitutes the main contribution of the paper. Next, we define the modified utility functions for the three players based on the adoption of the contract.

In order to formulate the reliability contract we must further describe our assumptions on natural gas procurement. We note that throughout the United States merchant gas power plants are relegated to purchase their gas in spot markets [18]. For the reliability contract we make two assumptions with regard to this process:

Assumption 7. *The fuel cost incurred by the NGPP is equal to that needed to cover RPP production shortfalls and its own commitments up to its maximum power output.*

In practice, there would be a cost associated with selling back unused gas, which is neglected in this paper, leading to Assumption 8.

Assumption 8. *The NGPP does not face quantity discounts when procuring gas.*

The main objective behind the reliability contract is to enable excess NGPP capacity to cover RPP shortfalls. This is accomplished through the introduction of a cash flow from the RPP to the NGPP during time periods of RPP shortfalls. This cash flow is specified by a contract settlement price $\pi_{RC} = \beta \lambda_{DA}$ and quantity $G_{RC} = S_r^{RC}$. The contract price fluctuates with day-ahead energy market prices through the coefficient β. As discussed in Section II-A, the submission of commitment bids happens prior to the determination of λ_{DA} (see Fig.1 for a timeline). For this reason, the contract price and quantity will be an expected value at the time of bid submission.

Over the settlement period of the contract, the payment from the RPP to the NGPP must be greater than what the NGPP could have earned in the day-ahead energy market by bidding additional capacity and smaller than the penalty payment the RPP would have paid the ISO if it were to bid without a contract. With the introduction of this payment the RPP utility under the reliability contract u_r^{RC} is modified from the baseline case (1) and is now given by

$$u_r^{RC}(C_r^{RC}, \lambda_{DA}, \pi_{RC}, G_{RC}) = \lambda_{DA} C_r^{RC} - \mu_r C_r^{RC} - E_R[\pi_{RC} G_{RC}] \tag{7}$$

where the penalty paid by the RPP to the ISO for unmet commitments is removed and in its place we include the expected contract payment to the NGPP $E_R[\pi_{RC} G_{RC}]$.

The reliability contract offers the fast-ramping and relatively low-emission NGPP a new revenue stream and exclusivity over the fulfillment of the RPP's shortfall. Beyond the introduction of the contract payment, the NGPP now faces fuel and variable O&M costs that are subject to the stochasticity of renewable generation. The remaining obligation of unfulfilled RPP commitments is also transferred from the RPP to the NGPP, incentivizing the latter to appropriately trade-off reserving capacity for renewable shortfalls with additional income from day-ahead energy market commitments.

In case of shortfalls $S_r^{RC} > 0$, we consider two scenarios for the NGPP. The first is denoted by s_1, which is equal to 1 when the NGPP's capacity is not binding to fulfill both its day-ahead energy market commitment and the RPP's shortfall $P_{n,max} - C_n^{RC} - S_r^{RC} > 0$ and 0 otherwise. The

second is denoted by s_2, which is equal to 1 when the NGPP's capacity is binding and cannot meet both its own day-ahead energy market commitment and the RPP's shortfall $S_r^{RC} - (P_{n,max} - C_n^{RC}) > 0$ and 0 otherwise. In s_2 the NGPP faces the settlement penalty for the unmet commitment, as given by $E_R[s_2\lambda_P(S_r^{RC} - (P_{n,max} - C_n^{RC}))]$. The utility function for the NGPP under the reliability contract u_n^{RC} is therefore correspondingly modified from (2) as

$$
\begin{aligned}
u_n^{RC}(C_n^{RC}, \lambda_{DA}, \pi_{RC}, G_{RC}) = \lambda_{DA}C_n^{RC} + E_R[\pi_{RC}G_{RC}] \\
- \mu_n(C_n^{RC} + E_R[s_1 G_{RC}] + E_R[s_2(P_{n,max} - C_n^{RC})]) \\
- E_R[F_n[C_n^{RC} + s_1 G_{RC} + s_2(P_{n,max} - C_n^{RC})]] \\
- E_R[s_2\lambda_P(S_r^{RC} - (P_{n,max} - C_n^{RC}))] \quad (8)
\end{aligned}
$$

where the payment from the RPP is given by $E_R[\pi_{RC}G_{RC}]$. The expression breaks down the O&M costs and the fuel quantity by the two shortfall scenarios s_1 and s_2.

Lastly, we note that the CPP's utility function is unchanged in going from the no contract baseline to the reliability contract and can be expressed with similar terms that simply substitute the baseline naming convention B in (5) for the reliability contract RC. The reliability contract utility functions for the three players are therefore given by (7), (8) and (5).

Once the utility functions for the three players under the no contract baseline and the reliability contract have been established, we consider the utility maximization problem for the three players,

$$
\max_{0 \leq C_r \leq P_{r,max}} u_r(C_r, \lambda_{DA}, \pi_{RC}, \widehat{G}_{RC}) \quad (9)
$$

$$
\max_{P_{n,min} \leq C_n \leq P_{n,max}} u_n(C_n, \lambda_{DA}, \pi_{RC}, \widehat{G}_{RC}) \quad (10)
$$

$$
\max_{P_{c,min} \leq C_c \leq P_{c,max}} u_c(C_c, \lambda_{DA}), \quad (11)
$$

where each of the market participants selects the commitment that maximizes their expected profit subject to the physical limits of their power plant. Whether or not the RPP and NGPP partner through a reliability contract, they individually solve their own utility maximization problem. If a contract has been established, their utility functions are dependent on the contract price π_{RC} and the expected renewable shortfalls (contract quantity) $\widehat{G}_{RC}$. The sequential resolution of contract parameters followed by optimal commitments reflects the contract timeline, as illustrated in Fig. 1.

In Section II we have described the DA electricity market structure, a few underlying assumptions, and the utility functions used in the utility maximization problem of the three players for both the baseline case where no contract between the RPP and NGPP is established and the reliability contract scenario.

III. MAIN RESULTS

In this section, we present the conditions under which the reliability contract is feasible and advantageous. In Section III-A we will derive optimal commitments for the players under the baseline scenario (Theorem 1), where no partnership exists between the RPP and the NGPP and for the reliability contract scenario. In Section III-B we will provide conditions for a feasible reliability contract based on the profitability of the players and provide an expression for the distribution of profits from the reliability contract. Finally, in Section III-C we will derive a condition for reliability contracts that increase social welfare (Theorem 2).

A. Optimal Commitments

The utility functions of the RPP and CPP are concave with respect to the commitment variable, allowing for a solution to be found by setting the partial derivative of the utility function with respect to the commitment decision variable equal to zero. On the other hand, the negative c term in the fuel cost function of the NGPP yields a convex utility function, meaning that we require a more detailed understanding of the operating regime to determine the optimal commitment. In particular, we introduce $P_{n,max}^{RC} = (P_{n,max} - S_r^{RC})$, where the maximum power output of the NGPP is reduced by the RPP shortfalls. We note that in practice the NGPP must submit a bid prior to receiving information on the RPP's deviation, meaning that the optimal commitment will use NGPP's expected deviations $\widehat{G}_{RC}$ as opposed to realizations, S_r^{RC}.

Theorem 1. *The optimal commitments for the three players under the baseline scenario with no contract between the RPP and the NGPP are* $C^{B*} = (C_r^{B*}, C_n^{B*}, C_c^{B*})$ *where*

$$
C_r^{B*} = F_R^{-1}\left(\frac{\lambda_{DA} - \mu_r}{\lambda_P}\right) \quad (12)
$$

$$
C_n^{B*} = \begin{cases} 0 & u_n^B(C_n^B = P_{n,max}) \leq u_n^B(C_n^B = 0) \\ P_{n,max} & otherwise \end{cases}
$$
$$(13)$$

$$
C_c^{B*} = \frac{\lambda_{DA} - \mu_c - e}{2f}. \quad (14)
$$

Under the reliability contract between the RPP and NGPP the optimal commitments are $C^{RC*} = (C_r^{RC*}, C_n^{RC*}, C_c^{RC*})$ *where*

$$
C_r^{RC*} = F_R^{-1}\left(\frac{\lambda_{DA} - \mu_r}{\pi_{RC}}\right) \quad (15)
$$

$$
C_n^{RC*} = \begin{cases} 0 & u_n^B(C_n^{RC} = P_{n,max}^{RC}) \leq u_n^B(C_n^{RC} = 0) \\ P_{n,max}^{RC} & otherwise \end{cases}
$$
$$(16)$$

$$
C_c^{RC*} = C_c^{B*}. \quad (17)
$$

Proof: The RPP's optimum commitment C_r^{B*}, which maximizes RPP profits for the baseline scenario, is found by setting the derivative of (1) equal to zero as shown:

$$
\begin{aligned}
\frac{\partial u_r^B}{\partial C_r^B} &= \lambda_{DA} - \mu_r - \frac{\partial}{\partial C_r^B}\int_0^{C_r^B}\lambda_P S_r^{RC} f_R(r)\partial r \\
&= \lambda_{DA} - \mu_r - \lambda_P F_R(C_r^B)
\end{aligned} \quad (18)
$$

$$
C_r^{B*} = F_R^{-1}\left(\frac{\lambda_{DA} - \mu_r}{\lambda_P}\right). \quad (19)
$$

The NGPP's utility function (2) is convex; however, from (4) we know that between the operating bounds $P_{n,min}$ and $P_{n,max}$ the fuel cost is monotonically increasing. Additionally, because the second order coefficient c, is negative, the partial

derivative with respect to the commitment C_n is decreasing throughout the operating regime. Taking the partial derivative of the utility function, we obtain

$$\frac{\partial u_n^B}{\partial C_n^B} = \lambda_{DA} - \mu_n - b - 2cC_n^B. \qquad (20)$$

The first and second partial derivatives of the utility function with respect to the commitment C_n, are positive across the feasible operating range, implying that the maximum value of the utility function can be observed at $P_{n,max}$. Plugging in $P_{n,max}$ in (20) gives a condition for profitability and therefore a condition for nonzero bid quantities. The optimum NGPP commitment without a reliability contract is given by the function:

$$C_n^{B*} = \begin{cases} 0 & u_n^B(C_n^B = P_{n,max}) \le u_n^B(C_n^B = 0) \\ P_{n,max} & \text{otherwise.} \end{cases} \qquad (21)$$

Setting the partial derivative of the CPP utility function (5) with respect to the commitment decision equal to zero yields an optimum commitment quantity as given by

$$\frac{\partial u_c}{\partial C_c} = \lambda_{DA} - \mu_c - e - 2fC_c \qquad (22)$$

$$C_c^* = \frac{\lambda_{DA} - \mu_c - e}{2f}. \qquad (23)$$

Setting the partial derivative of the RPP utility function in the reliability contract scenario (7) with respect to the commitment decision equal to zero yields an optimum commitment quantity as given by

$$\frac{\partial u_r^{RC}}{\partial C_r^{RC}} = \lambda_{DA} - \mu_r - \frac{\partial}{\partial C_r^{RC}} \int_0^{C_r^{RC}} \pi_{RC} G_{RC} f_R(r) \partial r$$
$$= \lambda_{DA} - \mu_r - \pi_{RC} F_R(C_r^{RC}) \qquad (24)$$

$$C_r^{RC*} = F_R^{-1}\left(\frac{\lambda_{DA} - \mu_r}{\pi_{RC}}\right). \qquad (25)$$

We select a feasible but not necessarily optimal commitment level for the NGPP in the reliability contract due to the difficulty of deriving an analytical solution using the complex utility function (8), as given by

$$C_n^{RC*} = \begin{cases} 0 & u_n^{RC}(C_n^{RC} = P_{n,max}^{RC}) \le u_n^{RC}(C_n^{RC} = 0) \\ P_{n,max}^{RC} & \text{otherwise.} \end{cases} \qquad (26)$$

As explained in Section II-C, the CPP's utility function (5) is unchanged with the introduction of the reliability contract (other than through the impact in market prices if reliability contracts are widely adopted), meaning that its optimal commitment is also unchanged from the baseline scenario (23).

In (19) the baseline commitment of the RPP is increasing with λ_{DA}, the incentive from committing and selling an additional unit of power, and decreasing with λ_P, the penalty for overestimating generation by an additional unit of power. The O&M cost μ_r appears as a correction to the incentive in the numerator of our expression. This same structure is followed under the reliability contract in (25), where the penalty λ_P is replaced by π_{RC}, which is smaller in magnitude, yielding larger commitments from the RPP. This is the key mechanism for increasing renewable utilization in the proposed partnership.

In (21) the evaluation of the partial derivative at $P_{n,max}$ yields a condition relating plant fuel cost and O&M parameters with day-ahead pricing. If the market price for energy is too low to recover fuel and O&M costs at full capacity, the NGPP's bid will be equal to zero. If the plant is profitable at the maximum power output, then it will bid and generate at that output because there is no commitment decision that has a greater expected profit. This same structure is followed under the reliability contract in (25) with the added complexity of reserving capacity to fulfill renewable shortfalls S_r^{RC}. Given that this output level will allow the NGPP to have sufficient capacity to cover the shortfalls directly, rather than incur a penalty, it is superior to operating at the maximum capacity.

B. Contract Feasibility and Profit Distribution

The reliability contract can be further described by equations that relate the profitability of the NGPP with the penalty faced by the RPP, as well as conditions on the distribution of profits using the assumptions made in Section II. These conditions are critical for selecting appropriate RPP-NGPP pairs and determining contract conditions.

For a reliability contract with time horizon $i = 1, \ldots, T$, the total penalty for shortage faced by the RPP without a reliability contract $\sum_{i=1}^T \lambda_{P,i} S_{r,i}^B$ is an upper bound on the sum of the foregone day-ahead market income $\sum_{i=1}^T \lambda_{DA,i}(C_{n,i}^B - C_{n,i}^{RC})$ and the sum of the variable cost incurred by the NGPP in adopting the contract $\sum_{i=1}^T \mu_n S_{r,i}^{RC} + F_n(C_{n,i}^{RC} + S_{r,i}^{RC}) - F_n(C_{n,i}^{RC})$, as given by

$$\underbrace{\sum_{i=1}^T \mu_n S_{r,i}^{RC} + F_n(C_{n,i}^{RC} + S_{r,i}^{RC}) - F_n(C_{n,i}^{RC})}_{\text{NGPP variable cost increase with reliability contract}}$$
$$+ \underbrace{\sum_{i=1}^T \lambda_{DA,i}(C_{n,i}^B - C_{n,i}^{RC})}_{\text{NGPP foregone DA income}} \le \underbrace{\sum_{i=1}^T \lambda_{P,i} S_{r,i}^B}_{\text{RPP penalty in baseline case}}. \qquad (27)$$

We note that the sums utilize the total power covered by the NGPP due to RPP generation shortfalls in the contract period. This condition is a selection criterion for NGPP candidates that could engage in a reliability contract.

We assume that additional profit from the contract is allocated equally to the two players, which implies that

$$\sum_{i=0}^T u_{r,i}^{RC}(C_{r,i}^{RC}, \lambda_{DA,i}, \pi_{RC,i}, G_{RC,i}) - u_{r,i}^B(C_{r,i}^B, \lambda_{DA,i}) =$$
$$\sum_{i=0}^T u_{n,i}^{RC}(C_{n,i}^{RC}, \lambda_{DA,i}, \pi_{RC,i}, G_{RC,i}) - u_{n,i}^B(C_{n,i}^B, \lambda_{DA,i}). \qquad (28)$$

This condition provides a means to compute β. Given that the RPP's commitment is dependent on β, the contract price coefficient can be determined *ex ante* using expected penalties and historic commitment data in practice. The contract could also include a profit true-up and re-allotment after the contract period has terminated.

C. Welfare Implications

Following the derivation of optimal commitments and feasible contract properties in the previous subsections we now aim to find the conditions under which the adoption of a reliability contract increases social welfare, which we define as the sum of the utilities of all the participants in the market $SW = u_r + u_n + u_c$. The CPP is a stand-in for all other players in the electricity market. If the sum of the utilities of the three players in the market increases (i.e. $SW^B \leq SW^{RC}$), the contract improves the operation of the system as measured by social welfare.

In the baseline case, social welfare will be given by the sum of the baseline utility functions of the players (1), (2) and (5), equivalent to

$$SW^B = (\lambda_{DA} - \mu_r)C_r^B - E_R\left[\lambda_P S_r^B\right] + \lambda_{DA}C_n^B$$
$$- \mu_n C_n^B - F_n(C_n^B) + (\lambda_{DA} - \mu_c)C_c^B - F_c(C_c^B). \quad (29)$$

When a reliability contract is signed, the social welfare expression is given by the sum of (7), (8) and (5), equivalent to

$$SW^{RC} = (\lambda_{DA} - \mu_r)C_r^{RC} + \lambda_{DA}C_n^{RC} + (\lambda_{DA} - \mu_c)C_c^{RC}$$
$$- \mu_n(C_n^{RC} + E_R[s_1 G_{RC}] + E_R[s_2(P_{n,max} - C_n^{RC})])$$
$$- E_R[F_n[C_n^{RC} + s_1 G_{RC} + s_2(P_{n,max} - C_n^{RC})]]$$
$$- E_R[s_2\lambda_P(S_r^{RC} - (P_{n,max} - C_n^{RC}))] - F_c(C_c^{RC}). \quad (30)$$

We note that, in this case, the terms corresponding to the payment of the contract are canceled out, since they are seen as an internal money transfer from the social welfare perspective.

We proceed with the analysis assuming that the day-ahead energy price is high enough for all the players to bid nonzero quantities which are fully cleared by the ISO. The commitments are determined following the procedure set forth in Section III-A but are restricted to the nonzero portions of the expressions given by (19), (21), (23), (25) and (26).

Per Assumption 3, all of the market participants bid their optimal, price-taking marginal cost commitments. For the NGPP in the reliability contract scenario, where it is required to bid under uncertainty, we add the following:

Assumption 9. *The NGPP chooses a sub-optimal yet feasible commitment when a reliability contract is adopted as given by (26).*

The NGPP's bid under uncertainty is $P_{n,max}^{RC} = (P_{n,max} - \widehat{G}_{RC})$. Using the assumption above, our goal is to show that a set of conditions exist such that a reliability contract between the RPP and the NGPP is feasible, even with a sub-optimal commitment from the NGPP. With that, it follows that there will also be conditions that make the contract feasible when the

NGPP bids its optimal commitment, even though we cannot show it analytically.

Theorem 2. *Under the condition*

$$\underbrace{E_R[s_2\lambda_p(S_r^{RC} - \widehat{G}_{RC})]}_{\text{NGPP penalty in contract case}} + \underbrace{\lambda_{DA}\widehat{G}_{RC}}_{\text{NGPP loss in revenue}}$$
$$\leq \underbrace{E_R[\lambda_p S_r^B]}_{\text{RPP penalty in baseline case}} \quad (31)$$

the adoption of a reliability contract increases social welfare $SW^B \leq SW^{RC}$.

Proof: Substituting the NGPP commitments (21) and (26) in the social welfare expressions, we find

$$\lambda_{DA}(C_r^{RC} - \widehat{G}_{RC}) - \mu_r C_r^{RC} - E_R[s_2\lambda_p(S_r^{RC} - \widehat{G}_{RC})]$$
$$- \mu_n(E_R[s_1 S_r^{RC}] + E_R[s_2\widehat{G}_{RC}] - \widehat{G}_{RC})$$
$$- E_R[F_n(P_{n,max} - \widehat{G}_{RC} + s_1 S_r^{RC} + s_2\widehat{G}_{RC})]$$
$$\geq (\lambda_{DA} - \mu_r)C_r^B - E_R[\lambda_P S_r^B] - F_n(P_{n,max}). \quad (32)$$

We now make two observations about the NGPP costs from the baseline to the reliability contract scenario: (1) the fuel cost will not increase given that the NGPP commits its maximum capacity in the baseline scenario, and thus the fuel cost in this case is the maximum that the player can incur, since a production greater than $P_{n,max}$ is not feasible. This observation implies

$$E_R[F_n(P_{n,max} - \widehat{G}_{RC} + s_1 S_r^{RC} + s_2\widehat{G}_{RC})]$$
$$\leq F_n(P_{n,max}). \quad (33)$$

(2) the O&M cost will not increase given that in the contract case, the NGPP decreases its day-ahead commitment by $\widehat{G}_{RC}$. In real-time, the cost associated with using that remaining capacity to cover renewable shortages will be at most the cost that the player would have incurred in case he had decided to use that capacity in the DA market instead. This observation implies

$$\mu_n(\widehat{G}_{RC} - E_R[s_1 S_r^{RC}] - E_R[s_2\widehat{G}_{RC}]) \geq 0. \quad (34)$$

With that, we find the condition

$$(\lambda_{DA} - \mu_r)C_r^{RC} - \lambda_{DA}\widehat{G}_{RC} - E_R[s_2\lambda_p(S_r^{RC} - \widehat{G}_{RC})]$$
$$\geq (\lambda_{DA} - \mu_r)C_r^B - E_R[\lambda_p S_r^B]. \quad (35)$$

Since we know that $C_r^{RC} > C_r^B$, we can write a stronger condition as

$$E_R[s_2\lambda_p(S_r^{RC} - \widehat{G}_{RC})] + \lambda_{DA}\widehat{G}_{RC} \leq E_R[\lambda_p S_r^B]. \quad (36)$$

∎

If (36) holds, then the NGPP and the RPP will increase their combined profits with the adoption of the contract without changing the utility of the other market participants. Notice, however, that the converse is not necessarily true. In Section IV, we show through numerical simulation that the contract also increases the profits of individual players.

In summary, in this section, we have derived the optimal commitments of the three players under the baseline scenario (19), (21) and (23) as well as for the reliability contract (25), (26) and (23). We have also derived an expression for selecting appropriate RPP-NGPP pairs for the reliability contract (27) and a condition for finding the contract price (28). Finally, based on the optimal commitments derived in subsection III-A, we have found a condition for reliability contracts that increase social welfare (36).

IV. SIMULATIONS

The analytical solutions for the optimal player commitments derived in Section III are employed in this section to evaluate the performance of the reliability contract under real-world conditions through simulation. The description of the simulation design, the datasets used, and our simulation results are described in what follows.

We selected a 50.6 MW wind power producer (WPP) and a 258MW combined-cycle NGPP in Roxbury and Rumford, ME respectively. Given that they inject at buses with no observed transmission constraints, and in physical proximity to one another (approximately 16 km [28]), they are treated as a common bus and pricing node. These two power producers were used to simulate the yearly cash flows of the baseline scenario, where the WPP faces penalties for shortfalls, and the reliability contract scenario, where the NGPP assumes any WPP shortfalls as described in Section II-C.

The selection of power plants was carried out by first mapping New England's NGPPs, WPPs, primary natural gas pipelines and electrical transmission lines as shown in Fig. 2. We observed that most of the NGPPs in the New England territory are located in the vicinity of load centers, particularly the Boston area, whereas sizeable WPPs have been developed in the north of the region. We selected a few of the large WPPs in Maine based on their electrical network proximity to NGPPs. The Rumford Combined Cycle NGPP revealed a low capacity factor (18.2%) and high ramp rates with respect to the neighboring WPPs' capacities (>30MW/min), signaling it as a great candidate for our simulations. The Roxbury WPP was selected from the WPPs in electrical proximity to the Rumford NGPP given its relatively large installed capacity. Select operational parameters of the two power producers are provided in Table I [29].

The bids of the partners follow the optimal commitments derived in Theorem 1, (19) and (25) for the RPP and (21) and (26) for the NGPP in the baseline scenario and the reliability contract scenario respectively. However, we conservatively assume that the NGPP is unable to predict renewable shortfalls (i.e. $\widehat{G}_{RC} = 0$). Due to data availability considerations, the simulation followed the 2016 calendar year. Additionally, the contract settlement and the determination of the optimal contract price coefficient β using (28) was completed under a fixed penalty coefficient α at the optimal commitments for the year interval, yielding one value for each of the relevant metrics (renewable utilization, unmet commitments, profit of each player). It should be noted that the results of this section reflect the optimal contract for a given α given the deterministic, *ex post* manner in which β is determined.
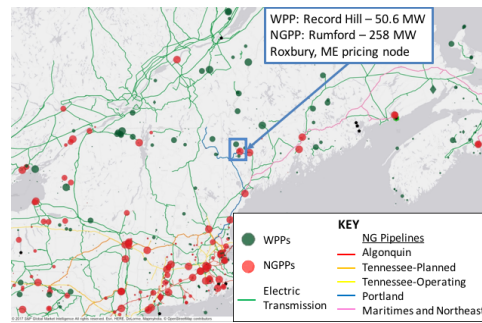

Fig. 2. Map of existing WPPs, NGPPs, electrical transmission lines and natural gas pipelines in New England developed with S&P Global Market Intelligence mapping tool and source databases [30]. The size of the marker relates to the capacity of the power plants.

TABLE I
WPP AND NGPP PARAMETERS [29]

Parameter	WPP	NGPP
P_{min} [MW]	0	56.8
P_{max} [MW]	50.6	258
μ [$\$/MWh$]	2.25	4.15
Fixed O&M (2016) [$k\$/year$]	960	$3,431$
Load factor (2016) [%]	27.5	18.2
Net Generation (2016) [GWh]	122.1	413.2

A. Dataset Description

Beyond the power plant technical datasheets from [29], which were used in selecting the WPP and NGPP, performance data for the NGPP (such as ramp rates and minimum partial load) was drawn from the manufacturer specification materials [31], performance comparison plots provided by [32] and Thermal Flow GT Pro simulations [33]. The NGPP's fuel cost function (3) parameters were determined from the performance characteristics of the plant, where $a = 13.93 MMBTU.th$, $b = 7.68 MMBTU.th/MW.e$ and $c = -0.005 MMBTU.th/MW.e^2$. The NGPP's hourly generation profile was estimated from the fuel cost function, the bidding strategy (26), the technical characteristics of the plant, the ISO's hourly energy market prices for the Rumford/Roxbury pricing node [34] and delivered natural gas prices [35] to match the 2016 load factor. Given the lack of firm fuel contracts for NGPPs, as was described in Section II-C, all gas was assumed to be procured from Dominion South daily spot market prices and transported through the Portland Pipeline.

The WPP's generation profile was developed using NREL's SAM [36] which resulted in a yearly net generation error of less than 1%. The wind resource profile used was the 2012 NREL WIND toolkit dataset for Northern Maine. The remainder of parameters such as the turbine characteristics were closely mapped to the technical datasheet [29] and installation information that could be inferred from aerial images [28], such as the configuration of the turbines (single column of 22 turbines) and the distance between the turbines (average spacing of 250m). In practice, WPPs injecting in ISONE pricing nodes receive forecasts prior to day-ahead bid submission [37]. Given that these forecasts are not publicly
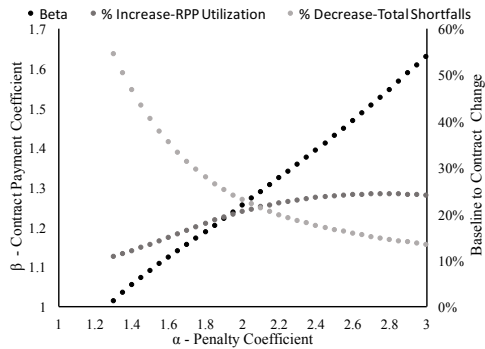
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Fig. 3. Yearly simulation results for the WPP-NGPP pair under feasible reliability contracts. The penalty coefficient α is plotted against the contract price coefficient β on the primary y-axis. On the secondary y-axis we plot the increase in wind power utilization and the decrease in total shortfalls (WPP & NGPP) as a percentage of total wind power generation available. The renewable utilization increase between the baseline and the contract scenario increases over the range of penalty prices. As penalty coefficients increase, the reliability contract becomes more attractive to the WPP as it would otherwise face increased curtailments from its ever decreasing optimal commitments. The differential in total shortfalls for the adoption of the contract is found to be decreasing along the penalty coefficient range as the WPP bids decrease for the baseline scenario. Unmet commitments under the reliability contract decrease a mere 2.1% to 1.7% whereas the baseline scenario shortfalls range between 56.7% and 14%.

available, the ISONE wind forecast data for the total installed capacity in the region [38] was scaled based on the capacity of the Rumford WPP.

B. Results and Interpretation

The year cash flow simulations for the Roxbury WPP and Rumford NGPP resulted in feasible contracts (with equal increases in profits for the two parties) for penalty coefficient $\alpha \geq 1.3$. Fig. 3 portrays the approximately linear increase in β between 1.01 and 1.63 with increasing α between 1.3 and 3.

Moreover, an increase in renewable utilization is observed across the simulations. A representative day of the WPP's forecast profile, bid before and after the reliability contract and actual power output are shown in Fig. 4. For this day, renewable utilization increases in 18 of the 24 hour periods. From the viewpoint of the simulation year, renewable utilization increases from 47.3% to 71.3%.

Across the simulations, we also note that the additional O&M costs faced by both the WPP and NGPP under the reliability contract (result of the WPP's increased bidding quantity) are offset by the reduction in total penalty payments to the ISO. An example of the total cash flows across the two-settlement market for the WPP-NGPP pair are shown in Table II where $\alpha = 1.5$, yielding an optimal $\beta = 1.09$. Profits increase by over 863 thousand dollars for each player, while renewable utilization increases from 74.9% to 88.2%. From the comparison between this simulation with $\alpha = 1.5$ and the previous simulation with $\alpha = 3$, we note that the baseline renewable utilization decreases while the change in renewable utilization increases with the reliability contract as penalty coefficients increase.

These results are not confined to the specific WPP-NGPP pair selected for simulation. For each of the 67 WPPs currently
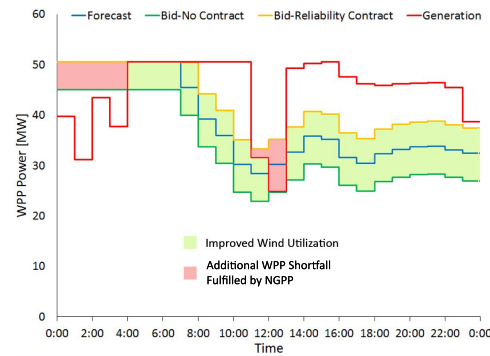

Fig. 4. WPP day-ahead forecast, baseline scenario bid, reliability contract scenario bid and actual power output for a representative day of simulation (January 13) with $\alpha = 3$ and $\beta = 1.63$. Increase in renewable utilization observed in 18 of the 24 hours of simulation. Total renewable utilization for the simulation year increases from 47.3% to 71.3%

TABLE II
WPP AND NGPP YEARLY CASH FLOWS [$ IN THOUSANDS]

Reliability Contract	No	No	Yes	Yes
Power Plant	WPP	NGPP	WPP	NGPP
Day-Ahead Income	$3,990	$19,028	$5,902	$19,028
Contract Payment	–	–	–$3,163	$3,163
Day-Ahead Penalties	–$2,150	–	–	–$237
Fuel Cost	–	–$7,352	–	–$9,014
Variable O&M Cost	–$196	–$1,632	–$232	–$2,033
Fixed O&M Cost	–$960	–$3,431	–$960	–$3,431
Profit	$685	$6,613	$1,548	$7,476

operating within ISO-NE (total installed capacity of 1,422 MW) the associated pricing node is 25 km or closer to the one corresponding to its closest NGPP, while the average distance is a mere 3.6 km. Even when restricting the NGPP type to combined cycle plants with operating capacities larger than the partner WPP, 1162 MW or 82% of the WPPs had pricing within $1.24/MWh of their partner NGPP during 2016.

In this section, we have provided evidence of a reliability contract, as specified by Sections II and III, that increases renewable utilization and the profits of the partners while reducing unmet commitments.

V. CONCLUSIONS AND FUTURE WORK

With large penetration of renewables such as wind and solar power into the generation mix, integration costs can rise significantly. It is quite likely that RPPs can experience a shortfall penalty when they are unable to fulfill their commitments in order to mitigate these costs. We propose an alternative to such penalties in this paper, in the form of a reliability contract between a RPP and an NGPP in the DA electricity market. The reliability contract is characterized by a payment from the RPP to the NGPP at times of unmet commitments, and is designed in such a way that it's economically advantageous to both the RPP and NGPP. For the RPP, the advantage is in the form of a smaller economic outlay compared to the penalty risk; for the NGPP, it introduces a new revenue stream and grants exclusivity to fulfilling the RPP's shortfalls. Through careful
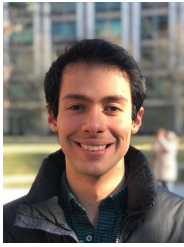
modeling of all the underlying utility functions, a condition is derived for feasible reliability contracts where there is a net increase in social welfare, as well as a condition for selecting NGPPs with the appropriate operational and maintenance costs to participate in these contracts. Both of these conditions form the foundation for market conditions where such a reliability contract is feasible.

In addition to providing an analytical foundation, we also validate the proposed reliability contract using data from a WPP and an NGPP in Northeastern United States. We demonstrate that over a range of scenarios where different penalty values are imposed by the ISO, increases in renewable utilization and profits for the WPP and the NGPP, as well as decreases in unmet commitments are observed. Although validation focused on an ISO setting, reliability contracts could be an attractive mechanism for renewable integration in balancing authorities (e.g. Montana) that require generators to self-provide reserves under the Open-Acccess Transmission Tariff (OATT).

In future work, we would like to explore the possibility of reducing the power output of the NGPP under high renewable generation conditions such that as much of the NGPP's commitment is fulfilled by renewable power as possible, further reducing total fuel burnt and increasing renewable utilization. We would also like to examine the impact of the adoption of reliability contracts on the natural gas system and how the adoption of a gas balancing market such as the one described in [23] may further enable the real-time procurement of fuel to relax Assumption 4. Additionally, we would like to explore how ISOs could use penalty pricing to strategically vary the integration of RPPs and the formation of reliability contracts for a set of system and environmental conditions.

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