

# Reliability Contracts Between Renewable and Natural Gas Power Producers

David D'Achiardi<sup>1</sup>, Nayara Aguiar<sup>2</sup>, Stefanos Baros<sup>1</sup>, Vijay Gupta<sup>2</sup>, and Anuradha M. Annaswamy<sup>2</sup>

**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 an energy market settlement, significant renewable generation curtailments would ensue, especially as the penetration of renewables grows. Based on the current evolution of policies toward 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. 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 an RPP-NGPP pair in the Northeastern U.S., the contract is shown to improve renewable utilization, increase the profits of both partners, and decrease total unmet commitments by the introduction of a lower cost alternative to the shortfall penalty.

**Index Terms**—Economic networks, electric power networks, game theory, natural gas power producers, optimal bidding, reliability contracts, renewable integration, social welfare.

## 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 U.S., these policies, by and large, have included the treatment of renewables as nondispatchable generators, largely allowing them to self-schedule as a negative load and exempting them from undergeneration 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 (RPPs). Broadly speaking, the 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 also by assessing the higher probability generation shortfalls of RPPs with respect to forecasts and commitments [2]. Additionally, the deviations from day-ahead (DA) and real-time energy market commitments place an additional stress on other power plants, which must also deviate from their commitments to fulfill demand. These costs are thought to be higher than the DA 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. The PJM and BPA in the USA [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 (RC) between an 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 the 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 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 a 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

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D. D'Achiardi, S. Baros, and A. M. Annaswamy are with the Department of Mechanical Engineering, Massachusetts Institute of Technology, Cambridge, MA 02139 USA (e-mail: davidhdp@mit.edu; sbaros@mit.edu; aanna@mit.edu).

N. Aguiar and V. Gupta are with the Department of Electrical Engineering, University of Notre Dame, Notre Dame, IN 46556 USA (e-mail: ngomesde@nd.edu; vgupta2@nd.edu).

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a baseline scenario with no contract between the RPP and the NGPP against the one with an RC.

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 by using the simulation of the described market and contract.

There are many directions of research relevant to this paper, which have been carried out in the literature. The work on grid costs of renewable intermittence is extensive; the reader is referred to [6] and the references therein. The boundaries of firms have been explored in the economics literature (e.g., seminal works such as [7]–[9] among others). Other groups have proposed partnering RPPs with dispatchable generators such as hydropower, which is specifically studied in [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 NGPP 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] and [15], which assume that the renewable and the NGPP *jointly* optimize their decisions, [16], which studies impact on natural gas prices due to volatility from renewable production in the power grid, [17], which studies the equilibrium of coupled gas and electricity markets, and [18], which 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] and [20].

The studies presented in [21] are the most relevant to this paper. They propose a bilateral contract between an RPP and an 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 RC 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 are used to validate our model for a set of players that could engage in an RC 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 RCs with an improved understanding of the NGPP gas procurement costs.

This 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 RC. 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 the simulations of the contract using resource and pricing data for an RPP and NGPP pair in Maine. Section V states the main conclusion of this paper 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 RC 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 DA 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 ISO, primarily tasked with meeting the demand reliably by using 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, thereby 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

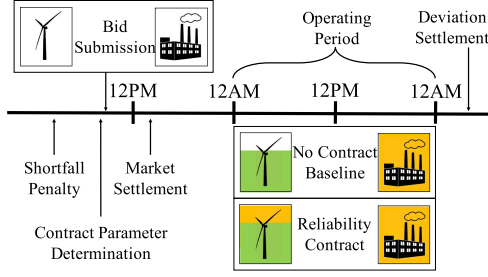


Fig. 1. Timeline for bid submission and market settlement under the no-contract baseline and the RC. The cleared, DA commitment of each player is shown in the black rectangles, whereas the real-time operation is shown by the shaded regions on the bottom right of the illustration.

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.

In practice, the ISO faces load uncertainty in the DA time horizon and bases commitment clearing decisions with respect to the 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,  $i = 1, \dots, 24$ , disregarding ramp constraints between intervals to establish an hourly DA schedule for the power plants.

The bids in the DA market are due 13 hours prior to the first operating period, corresponding to 11a.m. 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, an RPP,  $r$ , an NGPP,  $n$ , and a 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-A. The equilibrium commitments are found to be increasing with the DA market price,  $\lambda_{DA}$  and are discussed in detail in Section III-A. The players' bids are made before knowing the DA market price, which is a primary source of uncertainty in practice. For simplicity, we have not included the expectations for each mention of the DA market price, although the players will make decisions based on the expectation of  $\lambda_{DA}$ , disregarding the 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  $\lambda_{DA}$  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 that 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 neither consider fuel shortage challenges nor unplanned maintenance for the NGPP and CPP. As discussed in Section I, we do not consider the 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 DA 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  $\lambda_P$ , which varies with DA 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, the curtailment of RPPs is beginning to be introduced in the USA [4] and in Europe at present. The value of  $\lambda_P$  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 the simplicity of notation, expectation notation is not used for parameter  $\alpha$ .

Finally, the costs associated with variable operation and maintenance for the three market participants are given by  $\mu_r$ ,  $\mu_n$ , and  $\mu_c$ .

## 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 RC 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 RPP  $C_r^B$ , and DA market price  $\lambda_{DA}$ , 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 DA energy market income,  $\mu_r C_r^B$  the operation and maintenance costs incurred by the RPP, and  $E_R[\lambda_P S_r^B]$  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 DA energy market income and  $\mu_n C_n^B$  the operation and maintenance cost. We do not include a shortfall



penalty payment given that the NGPP always meets its commitment (see Assumption 4). We introduce the fuel payment function  $F_n$ , which maps a commitment in the 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 the data collected from operational power plants. A common model in the literature fits a second-order polynomial, as described in [26]. For the NGPP, the fuel costs are modeled as

$$F_n(P_n) = a + bP_n + cP_n^2 \quad (3)$$

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 the total power output to the 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, satisfying the following condition on positive marginal fuel cost:

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

The utility function for CPPs includes similar terms as follows:

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

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

$$F_c(P_c) = d + eP_c + fP_c^2. \quad (6)$$

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 RC 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 RC between the RPP and the NGPP, which constitutes the main contribution of this paper. Next, we define the modified utility functions for the three players based on the adoption of the contract.

In order to formulate the RC, 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 RC, we make the following 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 the 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 RC is to enable excess NGPP capacity to cover RPP shortfalls. This is accomplished by the introduction of a cash flow from the RPP to the NGPP during the 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 DA energy market prices through coefficient  $\beta$ . As discussed in Section II-A, the submission of commitment bids happens prior to the determination of  $\lambda_{DA}$  (see Fig. 1 for a timeline). For this reason, the contract price and quantity will be an expected value at the time of the 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 DA 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 RC  $u_r^{RC}$  is modified from baseline case (1) and is now given by

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

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 NGPP  $E_R[\pi_{RC} G_{RC}]$ .

The RC 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 tradeoff reserving capacity for renewable shortfalls with additional income from DA energy market commitments.

In the 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 DA 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 DA 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 RC  $u_n^{RC}$  is, therefore,

correspondingly modified from (2) as

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

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

Finally, we note that the CPP's utility function is unchanged in going from the no-contract baseline to the RC and can be expressed with similar terms that simply substitute the baseline naming convention  $B$  in (5) for the 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 RC have been established, we consider the utility maximization problem for the three players as

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

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

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

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 an RC, they individually solve their own utility maximization problem. If a contract has been established, their utility functions are dependent on the contract price  $\pi_{\text{RC}}$  and the expected renewable shortfalls (contract quantity)  $\hat{G}_{\text{RC}}$ . 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 RC scenario.

### III. MAIN RESULTS

In this section, we present the conditions under which the RC is feasible and advantageous. In Section III-A, we will derive the optimal commitments for the players under the baseline scenario (see Theorem 1), where no partnership exists between the RPP and the NGPP and for the RC scenario. In Section III-B, we will provide the conditions for a feasible RC based on the profitability of the players and provide an expression for the distribution of profits from the RC. Finally, in Section III-C, we will derive a condition for RCs, which increases social welfare (see 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 more detailed understanding of the operating regime to determine the optimal commitment. In particular, we introduce  $P_{n,\text{max}}^{\text{RC}} = (P_{n,\text{max}} - S_r^{\text{RC}})$ , 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,  $\hat{G}_{\text{RC}}$ , as opposed to realizations,  $S_r^{\text{RC}}$ .

**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

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

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

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

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

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

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

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

**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

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

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

The NGPP's utility function (2) is convex; however, from (4), we know that between the operating bounds  $P_{n,\text{min}}$  and  $P_{n,\text{max}}$ , the fuel cost is monotonically increasing. Additionally, because the second-order coefficient  $c$ , is negative, the partial derivative with respect to commitment  $C_n$  is decreasing throughout the operating regime. Taking the partial derivative of the utility

function, we obtain

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

The first and second partial derivatives of the utility function with respect to 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 an RC is given by the following function:

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

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

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

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

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

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

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

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

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

As explained in Section II-C, the CPP's utility function (5) is unchanged with the introduction of the RC (other than through the impact in market prices if RCs 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  $\lambda_{DA}$ , the incentive from committing and selling an additional unit of power, and decreasing with  $\lambda_P$ , the penalty for overestimating generation by an additional unit of power. The O&M cost  $\mu_r$  appears as a correction to the incentive in the numerator of our expression. This same structure is followed under the RC in (25), where the penalty  $\lambda_P$  is replaced by  $\pi_{RC}$ , 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

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

For an RC with time horizon  $i = 1, \dots, T$ , the total penalty for the shortage faced by the RPP without an RC  $\sum_{i=1}^T \lambda_{P,i} S_{r,i}^B$  is an upper bound on the sum of the foregone DA 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

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

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 an RC.

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

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

This condition provides a means to compute  $\beta$ . Given that the RPP's commitment is dependent on  $\beta$ , 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 reallocation after the contract period has terminated.

## C. Welfare Implications

Following the derivation of optimal commitments and feasible contract properties in the previous sections, we now aim to

find the conditions under which the adoption of an RC 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

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

When an RC 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 DA 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).

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

**Assumption 9:** The NGPP chooses a suboptimal yet feasible commitment when an RC is adopted as given by (26).

The NGPP's bid under uncertainty is  $P_{n,max}^{RC} = (P_{n,max} - \hat{G}_{RC})$ . Using the assumption above, our goal is to show that a set of conditions exist such that an RC between the RPP and the NGPP is feasible, even with a suboptimal 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

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

the adoption of an RC increases social welfare, that is,  $SW^B \leq SW^{RC}$ .

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

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

We now make two observations about the NGPP costs from the baseline to the RC 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

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

and 2) the O&M cost will not increase, given that in the contract case, the NGPP decreases its DA commitment by  $\hat{G}_{RC}$ . 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

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

With that, we find the following condition:

$$\begin{aligned} & (\lambda_{DA} - \mu_r)C_r^{RC} - \lambda_{DA} \hat{G}_{RC} - E_R[s_2 \lambda_P (S_r^{RC} - \hat{G}_{RC})] \\ & \geq (\lambda_{DA} - \mu_r)C_r^B - E_R[\lambda_P S_r^B]. \end{aligned} \quad (35)$$

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

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

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 other market participants. Notice, however, that the converse is not necessarily true. In Section IV, we show using 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 RC (25), (26), and (23). We have also derived an expression for selecting appropriate RPP-NGPP pairs for the RC (27) and a condition for finding the contract price (28). Finally, based on the optimal commitments derived in Section III-A, we have found a condition for RCs, which increases 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 RC under real-world conditions by using



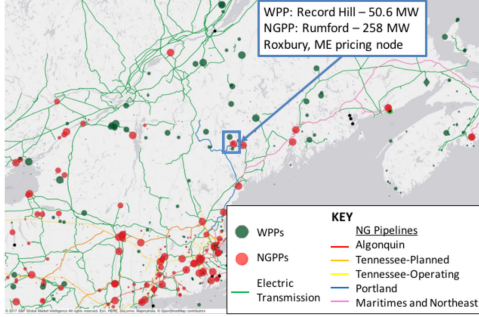


Fig. 2. Map of existing WPPs, NGPPs, electrical transmission lines, and natural gas pipelines in New England developed with S&P Global Market Intelligence mapping tool and source databases [30]. The size of the marker relates to the capacity of the power plants.

TABLE I  
WPP AND NGPP PARAMETERS [29]

| Parameter                   | WPP   | NGPP  |
|-----------------------------|-------|-------|
| $P_{min}$ [MW]              | 0     | 56.8  |
| $P_{max}$ [MW]              | 50.6  | 258   |
| $\mu$ [\$/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 |

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 258-MW combined-cycle NGPP in Roxbury and Rumford, ME, USA, 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 RC 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 ( $>30$  MW/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 RC scenario, respectively. However, we conservatively assume that the NGPP is unable to predict renewable shortfalls (i.e.,  $\hat{G}_{RC} = 0$ ). 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  $\beta$  using (28) was completed under a fixed penalty coefficient  $\alpha$  at the optimal commitments for the year interval, yielding one value for each of the relevant metrics (renewable utilization, unmet commitments, and profit of each player). It should be noted that the results of this section reflect the optimal contract for a given  $\alpha$ , given the deterministic, *ex post* manner in which  $\beta$  is determined.

### 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) were 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  $a = 13.93 \text{ MMBTU.th}$ ,  $b = 7.68 \text{ MMBTU.th/MW.e}$ , and  $c = -0.005 \text{ MMBTU.th/MW.e}^2$ . 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 250 m). In practice, WPPs injecting in ISONE pricing nodes receive forecasts prior to DA bid submission [37]. Given that these forecasts are not publicly 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  $\beta$  between 1.01 and 1.63 with increasing  $\alpha$  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 RC, and actual power output are shown in Fig. 4. For this day, the renewable utilization increases in 18 of the 24 hour periods. From the viewpoint of the



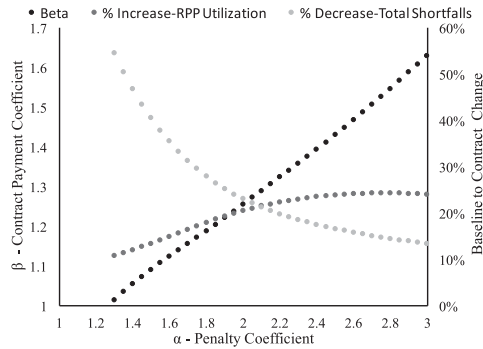


Fig. 3. Yearly simulation results for the WPP-NGPP pair under feasible RCs. The penalty coefficient  $\alpha$  is plotted against the contract price coefficient  $\beta$  on the primary y-axis. On the secondary y-axis, we plot the increase in wind power utilization and the decrease in total shortfalls (WPP and NGPP) as a percentage of the total wind power generation available. The renewable utilization increases between the baseline and the contract scenario increases over the range of penalty prices. As penalty coefficients increase, the RC becomes more attractive to the WPP, as it would otherwise face increased curtailments from its ever decreasing optimal commitments. The differential in the 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 RC decrease a mere 2.1% to 1.7% whereas the baseline scenario shortfalls range between 56.7% and 14%.

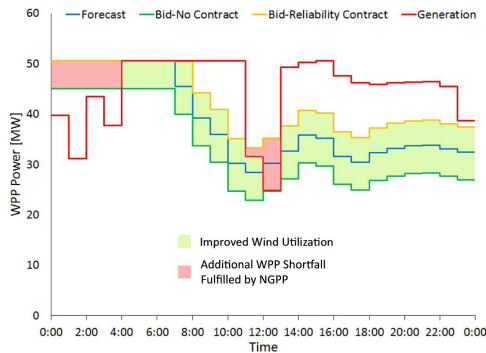


Fig. 4. WPP DA forecast, baseline scenario bid, RC scenario bid, and actual power output for a representative day of simulation (January 13) with  $\alpha = 3$  and  $\beta = 1.63$ . Increase in renewable utilization observed in 18 of the 24 hours of simulation. Total renewable utilization for the simulation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

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 RC (result of the WPP's increased bidding quantity) are offset by the reduction in the total penalty payments to the ISO. An example of the total cash flows across the two-settlement market for the WPP-NGPP pair is 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 the 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 the renewable utilization increases with the RC 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 op-

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  |

erating within ISO-NE (total installed capacity of 1422 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 the evidence of an RC, as specified in Sections II and III, which increases the renewable utilization and the profits of the partners while reducing unmet commitments.

## V. CONCLUSION 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 an RC between a RPP and an NGPP in the DA electricity market. The RC 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 is 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 for fulfilling the RPP's shortfalls. Through careful modeling of all the underlying utility functions, a condition is derived for feasible RCs, where there is a net increase in the 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 an RC is feasible.

In addition to providing an analytical foundation, we also validate the proposed RC by using data from a WPP and an NGPP in Northeastern United States. Over a wide range of penalty value scenarios, our simulations show that reliability contracts result in decreases in unmet commitments, increases in renewable utilization, and increases in profits for the WPP and the NGPP. Although validation focused on an ISO setting, RCs could be an attractive mechanism for renewable integration in balancing authorities (e.g., Montana) that require generators to self-provide reserves under the open-access transmission tariff.

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 RCs 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 RCs for a set of system and environmental conditions.

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**David D'Achiardi** received the B.S. degree in mechanical engineering and economics and the M.S. degree in mechanical engineering from the Massachusetts Institute of Technology (MIT), Cambridge, MA, USA, in 2016 and 2019, respectively.

He was a Mechanical Design Engineer at Tesla's Gigafactory 1, Reno, NV, USA. He is a Research Assistant with the Active-Adaptive Control Laboratory, Department of Mechanical Engineering, MIT. His research interests include energy market design under high renewable power adoption and transactive control of electric railway systems with distributed energy resources. Mr. D'Achiardi is the recipient of the 2017 Douglas and Sara Bailey Scholarship and the 2015 Carl G. Sontheimer Prize for Excellence in Innovation and Creativity in Design from the Department of Mechanical Engineering, MIT.



**Nayara Aguiar** received the B.S. degree in electrical engineering from the Federal University of Campina Grande, Campina Grande, Brazil, in 2016, and the M.S. degree in electrical engineering from the University of Notre Dame, Notre Dame, IN, USA, in 2018, where she is currently pursuing the Ph.D. degree in electrical engineering.

Her current research interests include the design and analysis of electricity markets in the presence of intermittent renewable energy generation.

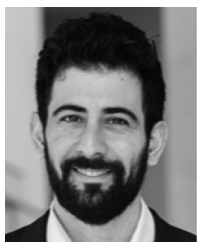
Ms. Aguiar is the recipient of the 2019 Patrick and Jana Eilers Graduate Student Fellowship for Energy Related Research, from the Center for Sustainable Energy at Notre Dame.



**Vijay Gupta** received the B. Tech degree in electrical engineering from the Indian Institute of Technology Delhi, New Delhi, India, and the M.S. and Ph.D. degrees in electrical engineering from the California Institute of Technology, Pasadena, CA, USA.

He is a Professor with the Department of Electrical Engineering, University of Notre Dame, Notre Dame, IN, USA, having joined the faculty in 2008. Prior to joining the University of Notre Dame, he was a Research Associate with the Institute for Systems Research, University of Maryland, College Park, MD, USA. His research and teaching interests are broadly at the interface of communication, control, distributed computation, and human decision making.

Prof. Gupta is the recipient of the 2018 Antonio Ruberti Award from the IEEE Control Systems Society, the 2013 Donald P. Eckman Award from the American Automatic Control Council, and a 2009 National Science Foundation (NSF) CAREER Award.



**Stefanos Baros** received the diploma degree in electrical and computer engineering from the National Technical University of Athens, Athens, Greece, in 2011, and the M.S. and Ph.D. degrees in electrical and computer engineering from Carnegie Mellon University, Pittsburgh, PA, USA in 2012 and 2016, respectively.

He is a Postdoctoral Research Associate with the Massachusetts Institute of Technology (MIT), Cambridge, MA, USA, Energy Initiative. From 2016 to 2018, he was a Postdoctoral Research

Associate with the Department of Mechanical Engineering, MIT, where he was affiliated with the Active-Adaptive Control Laboratory. His research interests include control of renewable energy resources, stability analysis of power systems with high penetration of inverter-interfaced renewable energy resources, optimal energy management in power systems, and design of efficient electricity markets.

Dr. Baros is the recipient of a number of awards, including the Grigorios Farakos Award (NTUA), ATK Vlahakis Fellowship (CMU), and more recently the American Society of Mechanical Engineers (ASME) Energy Systems Best Paper Award at the American Control Conference in 2016.



**Anuradha M. Annaswamy** received the Ph.D. degree in electrical engineering from Yale University, New Haven, CT, USA, in 1985. She is the Founder and Director of the Active-Adaptive Control Laboratory, Department of Mechanical Engineering, Massachusetts Institute of Technology, Cambridge, MA, USA. Her research interests span adaptive control theory and its applications to aerospace, automotive, and propulsion systems, as well as cyber physical systems such as smart grids, smart cities, and smart in-

frastructures. She has authored more than 100 journal publications and 250 conference publications, coauthored a graduate textbook on adaptive control, and coedited several cutting-edge science and technology reports including "Systems & control for the future of humanity, research agenda: Current and future roles, impact and grand challenges" (Annual Reviews in Control, 2016), *Smart Grid Control: Overview and Research Opportunities* (Berlin, Germany: Springer-Verlag, 2018), and "Impact of control technology" (IoCT-report 2011 and 2013).

Dr. Annaswamy is the recipient of several awards including the George Axelby (1986) and *Control Systems Magazine* (2010) Best Paper Awards from the IEEE Control Systems Society (CSS), the Presidential Young Investigator Award from the NSF (1992), the Hans Fisher Senior Fellowship from the Institute for Advanced Study at the Technische Universität München (2008), and the Donald Groen Julius Prize from the Institute of Mechanical Engineers (2008). She has been elected a Fellow of the IFAC (2017). She was the recipient of a Distinguished Member Award and a Distinguished Lecturer Award from the IEEE CSS in 2017. She is actively involved in the IEEE, IEEE CSS, and IFAC. She was the General Chair of the American Control Conference (2008) as well as the 2nd IFAC Conference on Cyber-Physical & Human Systems (2018). She is a Deputy Editor for *Annual Reviews in Control* (2016–present). She has been a member of the IEEE Fellows Committee and the IEEE CSS Outreach Committee and is the Chair of the IEEE Smart Grid Meetings and Conferences. In the IEEE CSS, she was the Vice President of Conference Activities (2015–2016) and Technical Activities (2017–2018) and will serve as the President in 2020.