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Two-settlement Systems for Electricity Markets under Network Uncertainty and Market Power*

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Abstract
We analyze welfare and distributional properties of a two-settlement system consisting of a spot market over a two-node network and a single energy forward contract. We formulate and analyze several models which simulate joint dispatch of energy and transmission resources coordinated by a system operator. The spot market is subject to network uncertainty, which we model as a random capacity derating of an important transmission line. Using a duopoly model, we show that even for small probabilities of congestion (derating), forward trading may be substantially reduced, and the market power mitigating effect of forward markets (as shown in Allaz and Vila 1993) may be nullified to a great extent. There is a spot transmission charge reflecting transportation costs from location of generation to a designated hub whose price is the underlying for the forward contract. This alleviates some of the incentive problems associated with the forward market in which spot-market trading is residual. We find that the reduction in forward trading is due to the segregation of the markets in the constrained state, and the absence of natural incentives for generators to commit to more aggressive behavior in the spot market (the "strategic substitutes" effect). In our analysis, we find that the standard assumption of "no-arbitrage" across forward and spot markets leads to very little contract coverage, even for the case with no congestion. We present an alternative view of the market where limited intertemporal arbitrage enables temporal price discrimination by competing duopolists. In this framework, we assume that all of the demand shows up in the forward market (or that the market is cleared against an accurate forecast of the demand), and the forward price is determined using a "market clearing" condition.

Key words: electric power industry, restructuring, market power, forward markets, spot markets, electric power transmission, network congestion

JEL Classification: L13, L94

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1. Introduction

In the past few years, wholesale electricity markets have gone through fundamental changes in the United States and around the world.[1] Electricity industry restructuring began in Latin American countries in the early 1980s, and more famously, in the United Kingdom in 1990. In the late 1990s, several U.S. states or control areas such as California, Pennsylvania–New Jersey–Maryland (PJM) Interchange, New York, and New England established markets for electricity; and more recently, FERC Order 2000 has prompted several proposals for the establishment of regional transmission organizations (RTOs). Two key common aspects of the transition toward competitive electricity markets in the United States and around the world are a competitive generation sector and open access to the transmission system. However, there is considerable diversity among the implementation paths chosen by different states and countries. The differences are reflected in various aspects of market design and organization, such as groupings of functions, ownership structure, and the degree of decentralization in markets. The experience gained from the first wave of restructuring in places such as the United Kingdom, Scandinavia, California, and PJM, have led to several reassessment and revision proposals of various market design aspects in these jurisdictions.

Two major themes in market design have emerged in the restructuring process, and have been implemented or currently proposed for the various markets in the United States (see Wilson 1999 for an overview of different market architectures). The first one, relies on centralized dispatch of all resources in the market, variations of which are implemented in the PJM Interchange, New York, and New England (see Garber et al. 1994; Budhraja and Woolf 1994). In this design, an independent system operator runs a real-time market with centralized dispatch. Bilateral trades are allowed in this system though they are purely financial in nature and do not get scheduling priority. Bilateral trades are charged locational price differences in the real-time market, and these can be hedged by some type of transmission congestion contracts, which are again financial instruments that guarantee the holder the price differential between locations specified in the contract (see Hogan 1992 and Harvey et al. 1997).[2]

The second design relies on a more decentralized approach, at least in the day-ahead energy market. The version that was originally implemented in California had two separate entities, a power exchange (PX), which was one of many short-term forward markets, and an independent system operator (ISO), which managed real-time operations (see Blumstein and Bushnell 1994; Wilson 1997).[3] The version implemented in Texas relies on bilateral trading and private exchanges for day-ahead energy trading, and some of the emerging RTOs also rely on various forms of decentralized day-ahead markets. The key feature of this scheme is that day-ahead energy trading and settlements are based on a

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1 See Einhorn (1994), Gilbert and Kahn (1996), and Chao and Huntington (1998) for surveys on the subject.

2 Current implementations at PJM, New York and New England allow physical bilateral contracts, which are interpreted as zero offers on the injection side and infinite bids on the load side.

3 The PX was dissolved in January, 2001.

simplified ‘‘commercial model’’ of the transmission network where nodes are grouped into few zones, and only few interzonal transmission constraints (deemed commercially significant—CSC) are enforced (i.e., priced) on day-ahead schedules submitted to the system operator. Congestion on CSCs can be hedged through financial or physical rights on these constrained interfaces. Such zonal aggregation facilitates liquidity of the day-ahead market but it allows scheduling of transactions that are physically impossible to implement due to reliability constraints. A centrally coordinated real-time physical market in which operational decisions are based on an accurate ‘‘operational model’’ of the transmission grid corrects these infeasibilities. The extent to which financial settlements in the real-time market reflect operational realities is a highly debated issue that is not yet resolved in many of the emerging RTOs. The debate concerns the extent to which the costs of correcting infeasible schedules should be directly assigned to those that cause such infeasibilities, as opposed to socializing these costs through uniform or load-share based uplift charges.

Theoretical analysis and empirical evidence suggests that forward trading reduces the incentives of sellers to manipulate spot market prices by reducing the sensitivity of sellers’ profits to spot price fluctuations. Thus, forward trading is viewed as an effective way of mitigating market power at real time. It is also argued that setting prices at commitment time provides incentives for accurate forecasting and provides ex-ante price discovery that facilitates trading, helps operations and improves system reliability at reduced cost. There is, however, only limited theoretical analysis to support these assertions. Furthermore, it is not clear to what extent suppliers with market power have an incentive to engage in forward transactions. The limited amount of contracting in California (even after the ban by the California Public Utility Commission was removed) and the collapse of the California PX may suggest that some form of regulatory intervention (short of direct government purchases) might be required to insure that the public is protected by an adequate amount of forward contracts.

The main goal of this paper is to examine the extent to which a two-settlement system facilitates forward trading. In other words, we quantify how sellers will allocate their production between forward and spot sales when that decision is endogenous. We also examine the welfare and distributional implications of such a system in the presence of network uncertainty and generator market power. We model the centralized dispatch-type markets described above (see Kamat and Oren 2002 for models and analysis of systems with separated electricity and transmission markets). As a benchmark for comparison we use a single-settlement nodal model.[4] The answers to these questions depends on the extent to which speculative trades can arbitrage the difference between forward prices and the expected spot prices. In the absence of such arbitrage, generators may amplify their market power through strategic intertemporal price discrimination. In order to examine the effects of such discrimination, we will relax the prevailing ‘‘no arbitrage’’ assumption in the analysis of multisettlement markets and introduce an alternative sequential market clearing hypothesis. We perform our analysis under the assumption that generators use Cournot conjectural variations when making decisions. While this is a common

4 We ignore transmission contracts in this study, and focus on a market with a single zone.

assumption in single period models, there is an ongoing debate on its relevance in two-settlement systems. We recognize that our results may change based on the conjectural variation assumed. From a computational point of view, the Cournot assumption makes the problem relatively tractable while retaining the most important features such as network representation (see Wu et al. 2002; Wu and Kliendorfer, undated; and Wu et al. undated for analyzes building on different assumptions).[5]

The remainder of the paper is as follows. The next section provides a review of the relevant literature on spot market modeling, modeling interactions between spot and contract markets, and approaches to transmission pricing. Section 3 presents formulations of the various market designs analyzed in this study. In section 4, we analyze the impact of network uncertainty in a simple two-node example. Section 5 provides some concluding remarks and addresses future work.

2. Literature Review

We review literature on electricity market modeling, both with and without transmission constraints, and models with contracts. While some electricity market models have attempted to include transmission constraints, models with two-settlement systems (or forward energy contracts) usually treat the electricity market as if it is deliverable at a single location. We also review the market designs in greater detail specifically with respect to transmission pricing.

2.1. Electricity Market Models

Schweppe et al. (1988) originated the theory of competitive electricity locational spot prices. Given costs of all generators on the network, demand, and network topology, locational prices can be calculated using an optimal power flow model, which seeks to minimize the total cost of generation. In a decentralized environment, fully competitive environment, these prices can elicit the optimal quantities from competitive agents. Differences in locational prices reflect differences in equilibrium marginal costs at various locations, and can be used to set transmission charges for bilateral contracts (Schweppe et al. 1986; Hogan 1992). Later studies, however, have considered the effect of generator market power in electricity markets. Equilibria with two conjectural variations, supply function equilibria (see Klemperer and Meyer 1989), and Cournot–Nash equilibria have been examined.

2.1.1. Models without Transmission Constraints

Green and Newbery (1992), use supply function equilibria to describe the electricity spot market in England and Wales soon after deregulation in 1990.[6] In a supply function

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5 A recent study for the California System Operator where modest network representation and different conjectural variations were assumed faced severe convergence problems.

6 One of the arguments in favor of deregulation of the generation sector was that generators would compete as Bertrand oligopolists and this would result in competitive prices. Also, it was argued that the

equilibrium (SFE), each firm submits a non-decreasing supply function specifying the quantity it is willing to provide at a given price. These functions can be derived as solutions to a set of coupled differential equations. Green and Newbery find that in the short-term (until new entry that was proposed was set up), the incumbents had significant market power, and large deadweight losses could result if they compete in a SFE. They also argue that the amount of planned entry is more than is socially desirable, and could cause substantial deadweight losses in the future due to the unnecessary expense in investment. Bolle (1992) also considers several models of SFE in which consumers react to a fixed price, to average spot prices, and directly to spot prices. He allows for backward bending supply functions, and finds a continuum of equilibria in all cases. He recommends that consumers be directly exposed to spot prices as this is the only model in which increasing the number of firms results in more competitive behavior. Bolle (2001) extends the earlier analysis to include demand side bidding. In a detailed analysis, he derives power series solutions for supply function equilibria in supply and demand functions, and analyzes restrictions on free parameters of the solution in order to get meaningful solutions with positive prices and quantities, upward sloping supply functions and downward sloping demand functions, and positive excess supply to meet autonomous demand. Bolle finds that these restrictions may imply that prices may in general be bounded away from marginal cost and computes lower bounds for some cases.

Andersson and Bergman (1995) calculate Bertrand and Cournot–Nash equilibria under various assumptions in an ex-ante analysis of the Swedish electricity market. They find that deregulation is not a sufficient condition for lower equilibrium prices given the structure of the market at that time (two firms controled 75% of the market). They find that increasing the number of firms in the market to about five equal size firms would bring discipline to prices, as would higher demand elasticity and monopsony power.

Newbery (1995) examines equilibria with capacity constraints, and again considers issues of entry into the England and Wales market, while Green (1996) examines how many firms would be required for a more competitive market. Rudkevich et al. (1998) and Bohn et al. (1999) apply these techniques to U.S. markets. Rudkevich et al. (1998) propose an iterative scheme for linear marginal costs, which converges to the unique linear SFE for this case. Baldick et al. (2000) generalize this to the case of asymmetric plants with affine marginal costs, where supply functions can be linear or piecewise linear. They also propose an ad-hoc approach to deal with capacity constraints in this case.

von der Fehr and Harbord (1993) consider the electricity market in England and Wales as a multiunit auction and examine equilibria under capacity constraints. They find that when firms have to bid discontinuous step functions instead of continuous supply functions there are no pure strategy equilibria comparable to SFE equilibria. They find

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threat of entry by small and efficient combined cycle gas powered capacity would bring the necessary discipline to the market. In the immediate years after deregulation, however, a duopoly existed, with two firms—National Power and Powergen—controlling 80% of the generation capacity and with substantial price setting power. In the daily market run by the grid operator, National Grid Company, these firms submitted a supply schedule for each generator under their control. The grid operator aggregated these schedules, and using optimization software calculated a system marginal price, which was paid to all generators. Other payments for start-up costs and capacity availability were also made.

mixed strategy equilibria instead; though pricing above marginal costs is seen in many equilibria they derive. Marín Uribe and Garcia-Diaz (2000) extend von der Fehr and Harbord's model to allow for any technology mix and elastic demand in an application to the Spanish market.

In another application to the Spanish electricity market, Ramos et al. (1998) combine a traditional production cost model with equilibrium constraints for modeling profit maximizing by individual firms, and approximate a decentralized equilibrium in an ''optimization with equilibrium constraints'' framework. They maintain a detailed representation of the electric system operation by considering ramp-rates, minimum up and down times, and operational features of hydro plants. However, they compute linear prices, i.e., there is a uniform price paid to all generation in a period, and so, total amount paid to generation across periods is linear in price for any period. It is not clear whether in a decentralized situation such linear equilibria exist due to the non-convexities in the cost-structure.[7]

2.1.2. Models with Transmission Constraints

Most of the models with transmission constraints assume the Cournot conjectural variation.[8] An important modeling choice in these models is the assumption on whether agents will game transmission markets. This may have an impact on the amount of congestion rent paid to transmission rights holders. Assuming that agents will game the market, however, leads to non-convex problems with possibly multiple equilibria (see Oren 1997a; Cardell et al. 1997 among others).[9] On the other hand, if the main purpose of the model is to model generator behavior in the energy market, assuming that agents act as price takers in the transmission market allows the models to be solved as complementarity problems or variational inequalities (see Hobbs 2001; Smeers and Wei 1997b).

Cardell et al. (1997) consider a model with Cournot generators who may own plants at multiple locations on a network, and a competitive fringe that takes the strategic generators' quantities as given, and act as price takers in the spot market. A complicating feature of this model is that with the introduction of a competitive fringe, a given strategy profile of the generators may not lead to a unique outcome in the spot market. Another feature is that the strategy sets, and not just the objective function values, of the generators depend on the actions chosen by other generators. This type of game is called a ''generalized Nash game'' (see Harker 1991) and can have multiple equilibria. Cardell et al. (1997) use an iterative procedure, solving a relaxed form of each Cournot generator's non-convex optimization problem in sequence, and report that a nonlinear solver always found solutions that satisfied a Cournot equilibrium test. A significant result coming out of their work is that generators owning multiple units on a network may not necessarily reduce output in all of them. In fact, increasing output on some generators may give it a

7 See Johnson et al. 1997.

8 See Smeers (1997) for a discussion on computable equilibrium models of restructured electricity markets. A variation on the Cournot assumptions is to model supply function equilibria using a scalar or two-parameter strategy vector (see Berry et al. 1999; Hobbs et al. 2000; Day et al. 2001).

9 See Luo et al. (1996) for a comprehensive analysis of such problems.

strategic advantage by forcing out some competition on another part of the network, and due to transmission constraints, allow it to earn more profits on its remaining capacity (also see Hogan 1997). Hobbs et al. (2000) solve a similar problem, where generators have a scalar intercept mark-up strategy, using an interior point algorithm. Their model does not consider a competitive fringe.[10] Berry et al. (1999) consider the effect of network structure and capacity limits on competitive behavior in linear supply functions. They retain the assumption that generators game the transmission network. Using two and four node network examples, they show that effective transmission congestion rent can be reduced through strategic bidding in supply functions. Other effects such as decreased efficiency from decreasing concentration are also observed in a four node network.

Borenstein et al. (1999) show that interactions among Cournot generators in the presence of a transmission constraint can be quite complex. They show that in a spatially separated market with a symmetric duopoly, and with a small enough transmission line, no pure strategy Cournot equilibria exists. This is due to the fact that there are discontinuities in the response functions of the generators. Along the response function, one generator produces a constant amount, congesting the transmission line in the direction of the other market until the other generator's production reaches a threshold level, at which point it increases its output proportionally. At another threshold level, the first generator abandons this strategy and reverts to a defensive strategy with smaller production than in the first case mentioned above. The authors also analyze cases where passive-aggressive or multiple equilibria can exist.

The above approach of solving generators' optimization problem sequentially implies that generators will take into account how their actions affect transmission prices. Some other models do away with this complication by assuming that generators do not game the transmission system. This removes the non-convexity from each generator's optimization problem. First-order conditions for all the generators can now be aggregated along with those of transmission owners, and the equilibrium can be solved as a complementarity problem. Wei and Smeers (1997) consider a Cournot model with regulated transmission prices (Smeers and Wei 1997b consider a model with a transmission market). They solve variational inequalities to determine unique long-run equilibria in their models. Smeers and Wei (1997a) consider a separated energy and transmission market, where the system operator conducts a transmission capacity auction, and power marketers purchase transmission contracts to support bilateral transactions. They find that such a market converges to the optimal dispatch for a large number of marketers. Borenstein and Bushnell (1999) use a grid search algorithm to converge iteratively to a Cournot model with data on the California market. Hobbs (2001) uses linearly decreasing demand and constant marginal cost functions, which result in linear mixed complementarity problems, to solve for such Cournot equilibria. In a bilateral market, Hobbs analyzes two types of markets, with and without arbitrageurs. In the market without arbitrageurs, non-cost based

10 Having a competitive fringe would imply that transmission prices reflect the opportunity cost of marginal energy trades. Cournot generators would therefore have less control over transmission revenues that the system operator collects. Assuming an intercept mark-up strategy gives the supplier in this paper an additional degree of freedom to manipulate congestion revenues.

differences can arise because the bilateral nature of the transactions gives generators more degrees of freedom to discriminate between electricity demand at various nodes. This is equivalent to a separated market as in Smeers and Wei (1997a). In the market with arbitrageurs, any non-cost differences are subject to arbitrage by traders who buy and sell electricity at nodal prices. This equilibrium is shown to be equivalent to a Cournot–Nash equilibrium in a POOLCO-type market.

2.1.3. Empirical Work on Market Power

Empirical evidence to support the hypothesis that electricity markets are susceptible to market power can be found in Borenstein et al. (1999), Wolfram (1998 and 1999), Mansur (2001), and Puller (2001). These studies focus on the U.K., California and PJM markets. Borenstein et al. (1999) calculate price cost margins in California by estimating expected aggregate marginal cost curves for thermal generation. They use system-wide demand as the market clearing quantity, and the unconstrained PX price as the market-clearing price. In calculating the marginal cost curve, they account for must-take generation, hydroelectric load, imports, etc., and for thermal capacity, they perform Monte Carlo simulation to calculate expected marginal cost at the net market clearing quantity for thermal capacity.[11] They find that overall prices averaged about 15% above the competitive level for the summer of 1998. Wolfram (1999) and Mansur (2001) use similar methodology for the U.K. and PJM markets, respectively. Puller (2001) uses firm-level data to analyze pricing behavior in the first two years of the California market. Puller tests both static and dynamics models of oligopoly, and finds evidence that generating firms used static market power in this period.

2.2. Electricity Market Models with Spot and Contract Markets

Work in this area has focused on the welfare enhancing properties of forward markets and the commitment value of forward contracts. Theoretical studies have shown that for certain conjectural variations, forward markets increase economic efficiency through a prisoners' dilemma type of effect (see Allaz 1992; Allaz and Vila 1993).[12] Other theoretical literature has analyzed the commitment value of contracts as barriers to entry (see Aghion and Bolton 1987). Applications to electricity markets seem to focus mainly on these two issues.

2.2.1. Theory

The basic model in Allaz (1992) is that producers meet in a two period market where there is some uncertainty in demand in the second period. In the first period, producers buy or sell contracts and a group of speculators take opposite positions. In the second period, a non-competitive market with Cournot conjectures is modeled. A no-arbitrage relation between forward and expected spot prices decides the forward price. If all speculators are

11 However, they do not include inter-temporal costs arising from unit-commitment constraints.
12 This effect is not seen, for example, with the Bertrand conjectural variation.

risk averse, the forward price contains a risk premium, otherwise if one or more risk neutral speculators are present, the forward price is an unbiased estimator of the spot price. Allaz shows that generators have a strategic incentive to contract forward if other producers do not. This result can be understood using the strategic substitutes and complements terminology of Bulow et al. (1985). Essentially, the Cournot conjectural variation implies that production quantities are strategic substitutes. This is because an increase in one producer's quantity has a negative effect on the other's marginal profitability, and thus its best response is lower than was previously optimal. The availability of the forward market makes a particular producer more aggressive in the spot market. Due to the strategic substitutes effect, this produces a negative effect on its competitor's production, and the resulting price decrease is not as severe as it would have been if its competitor had not reacted. The producer with access to the forward market can therefore use its forward commitment to improve its profitability to the detriment of its competitor.[13] Allaz shows, however, that if all producers have access to the forward market, it leads to a prisoners' dilemma type of effect, reducing profits of all producers. Social welfare measured as the sum of consumer and producer surpluses is higher than in a single-settlement case with producers behaving à la Cournot. Allaz points out that the results are very sensitive to the kind of conjectural variation assumed, and shows that Cournot and market-sharing conjectural variations in the forward market lead to very different results. Allaz and Vila (1993) extend this result to the case where there is more than one time period where forward trading takes place. For a case with no uncertainty, they establish that as the number of periods when forward trading takes place tends to infinity, producers lose their ability to raise market prices above marginal cost and the outcome tends to the competitive solution. Haskel and Powell (1994) extend these results to general conjectural variations in the spot market.

An important consideration in electricity markets is that generators meet in these markets almost on a daily basis. There is a rich literature on repeated games, which formalizes folk-theorem type results, in which producers often can play collusive looking outcomes in repeated setting which secure them above-Cournot profits. These results are sensitive to assumptions such as observability of past actions and the discount factor. It would be of interest to see what type of discount factors are needed to reverse the ''forward markets are welfare enhancing'' results in this literature. Producers in the Allaz (1992) model do not have a commitment device to stay out of the forward market, which essentially reduces their profitability in the overall game. A repeated game setting may provide a way for producers to commit to keeping their forward positions to a minimum, thus reversing some of these results.[14]

13 Bulow et al. (1985) warn, however, that assumptions of linearity on the demand often produces strategic substitutes, but that this may no longer be true if demand is constant elasticity or nonlinear.

14 There is a large literature on the commitment value of contracts, see e.g., Aghion and Bolton (1987) and Dewatripont (1988) for early contributions. Most of this literature criticizes the use of Pareto-dominated equilibria at later stages in a multi-stage game in order to select Pareto-superior equilibria in the overall game. If agents can renegotiate from a Pareto-dominated equilibria to some other equilibrium then the selection of the Pareto-superior equilibrium is in question. It is suggested that selected equilibria be renegotiation-proof.

2.2.2. Applications

von der Fehr and Harbord (1992) and Powell (1993) are early studies that include contracts, and examine their impact on an imperfectly competitive electricity spot market, the U.K. pool. von der Fehr and Harbord (1992) focus on price competition in the spot market with capacity constraints and multiple demand scenarios. They find that contracts tend to put downward pressure on spot prices. Although, this provides disincentive to generators to offer such contracts, there is a countervailing force in that selling a large number of contracts commits a firm to be more aggressive in the spot market, and ensures that it is dispatched in to its full capacity in more demand scenarios. They find asymmetric equilibria for variable demand scenarios where such commitment is useful. Powell (1993) explicitly models recontracting by regional electricity companies (Recs.) after the maturation of the initial portfolio of contracts set up after deregulation. He adds risk aversion on the part of Recs. to the earlier models. Generators act as price setters in the contract market, but compete in a Cournot equilibrium in the spot market. The Recs. set quantities in the contract market. He shows that the degree of coordination has an impact on the hedge cover demanded by the Recs., and points to a ''free rider'' problem which leads to a lower hedge cover chosen by the Recs. Batstone (undated) considers the implications of strategic behavior on the part of risk-neutral generators faced with cost uncertainty who contract with risk-averse consumers maximizing mean-variance utility. He shows that in equilibrium generators have an incentive to increase the variance in the spot market price to extract a larger forward premium, and increase profits by selling more contracts.

Newbery (1998) analyzes the role of contracts as a barrier to entry in the England and Wales electricity market. Newbery extends earlier work by modeling equilibria in supply functions in the spot market. For tractability he assumes constant marginal costs, which allow him to derive analytical solutions to the spot supply functions. He models risk-neutral consumers with a similar market structure as in Powell. Newbery shows that if entrants can sign base load contracts and incumbents have enough capacity, the incumbents can sell enough contracts to drive down the spot price below the entry deterring level. Newbery shows that this could result in more volatile spot prices if producers coordinate on the highest profit SFE. Capacity limits however may imply that incumbents cannot play a low enough SFE in the spot market and hence cannot deter entry. Green (1999) extends Newbery's model including linear marginal costs. An interesting result is that when generators compete in SFEs in the spot market, an assumption of Cournot conjectural variations in the forward market implies that no contracting will take place unless buyers are risk averse and willing to provide a hedge premium in the forward market.[15] The author points out the this is a function of linear SFEs derived in this study, and not a general result for SFEs. Lien (2001) extends these results by explicitly modeling entry into these markets. He shows that forward sales can deter excess entry, and increase

15 This result can also be understood in terms of Bulow et al. (1985) results. In Green's model, a particular firm's contract position has no effect on its competitor's spot market strategy, which means that there is no strategic substitutes effect.

economic efficiency and long-run profits of a large incumbent firm faced with potential entrants.

2.2.3. Transmission Pricing and Design of Transmission Capacity Rights

Though we do not consider transmission contracts in this paper, the interaction between forward transmission markets (mainly in the form of transmission capacity rights) and the spot energy market, and in particular, the influence of generator market power on the value of such rights has been studied in the literature. The role of the system operator in providing open-access to the transmission network and pricing scarce transmission resources (as per FERC Order 888, and more recently FERC Order 2000), and to its extent of involvement in energy and other unbundled energy product markets has also been a hotly debated issue over the past decade (see references in Kamat and Oren 2002). In a competitive market with centralized dispatch, locational prices are calculated at every node in the network (Schweppe et al. 1988). Congestion rent is then just the difference in locational prices between any two locations. Hogan (1992) shows that if transmission rights are financial rights to these locational price differences then this maximizes the value of the network. Under this paradigm, he proves revenue sufficiency of the system operator who provides access, i.e., the merchandizing surplus resulting from selling and buying power at nodal prices will cover the payments to transmission rights holders. The natural type of transmission rights that go with this scheme are point-to-point rights (see Harvey et al. 1997). These rights entitle the holder to the difference in locational prices between two points specified in the right. For some of the proposed markets in the United States there are proposals that call for flow-based transmission rights (also called flowgate rights or FGRs; see Chao and Peck 1996, 1997; Chao et al. 2000a). The idea is that in any electricity network only a small number of transmission lines are expected to be congested, and if forward markets are established only for these commercially significant flowgates they will be highly liquid and provide adequate price signals to internalize network externalities. This type of scheme also facilitates bilateral forward contracting.

The influence of generator behavior on the market value of financial transmission rights has also received attention. Using Cournot assumptions, Oren (1997) argues that generators at supply nodes will have enough market power to capture the entire market value of ''passive'' or financial transmission congestion contracts using two and three node examples. He argues that with ''active'' or physical rights, and parallel trading in energy and transmission markets, such abuse of market power will be limited; Stoft (1999) argues to the contrary, and suggests that financial rights do mitigate market power under slightly different assumptions. Joskow and Tirole (2000) provide a comprehensive analysis of how the allocation of transmission rights affects markets with generator and consumer market power. They find that the extent of the effects depends on the microstructure of the transmission rights markets and the distribution of market power. They find that purely physical rights have worse welfare properties than financial rights, but introducing a use-or-lose feature (which prevents withholding of physical capacity, but still honors the financial entitlement of the right) may help alleviate some of these adverse properties. Daxhelet and Smeers (2002) consider transmission pricing issues in the context of cross-border electricity trade.

3. Formulation

Our formulations try and capture several aspects of current electricity market designs that have been previously modeled in isolation. We focus on two-settlement systems in the presence of network uncertainty and market power. We model network uncertainty in the form of a random capacity derating of an important line in the transmission network. Studies with market power usually consider single-settlement systems, while the literature modeling interactions between spot and forward markets does not consider transmission constraints. As our focus is on understanding the mechanisms that drive our results, we analyze the problem with the help of several illustrative examples on simple two- and three-node networks. We formulate the problem as a two period game where generators use a Cournot conjectural variation in the spot market (period 2).[16] We assume that generators take transmission prices as given and do not try to game the transmission system (Hobbs 2001; Smeers and Wei 1997a make such an assumption). There is a probability r that one of the transmission lines is derated to a level that it will be binding in the spot market. In period 1, we model a forward market with a single contract for energy delivered in period 2.

In a two-settlement system it becomes necessary to describe accurately the commodity, or the commodity price in case of financial contracts, underlying the forward contract. Rather than choosing an arbitrary spatial location, we choose the underlying price as a ''virtual'' hub-price equal to the demand-weighted average spot price. As this is an energy contract, generators are charged a spot transmission charge for energy delivered at their location, which is equal to the difference between the hub-price and the nodal price at the generator's location. No transmission contracts are available to hedge this uncertain cash flow. In the presence of speculators who trade between the markets, the forward price will converge to the demand-weighted expected spot price (assuming risk-neutrality and zero interest rates), and this fact is used to determine forward prices in this case. In our example, we find that this model predicts relatively small aggregate positions in the forward market.[17] There seems to be ample empirical evidence that generators cover a large portion of their spot sales under forward contracts. There is also evidence that financial derivatives markets in electricity are generally illiquid, and trading in these markets, to the extent it exists, has been much less than in comparative markets for other commodities.

In the absence of speculators that can exploit arbitrage opportunities between the forward and spot market prices, generators can exercise their market power for intertemporal price discrimination and increase their profits by pricing forward contracts above the expected spot price. Arbitraging such price differences would require speculators to take short positions in the forward market and cover their positions in the spot market. Such arbitrage is considered as very risky given the high volatility of spot electricity markets which may explain the fact that we do not see much speculative trading

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16 We are not aware of any study that derives a general supply function equilibrium in presence of a transmission constraints.

17 This may change, although to a small extent, with the introduction of risk-aversion in the model.

of that sort. On the contrary, most speculative trading to the extent that it exist tends to involve long positions in the forward market which will further increase forward prices. Consequently, intertemporal price discrimination with higher forward prices can be sustained which raises questions regarding the validity of the Allaz–Vila (1993) model which rests on a no arbitrage assumption between forward and spot prices. The lack of uncovered short positions for short-term forwards has been recently brought up in litigation at the FERC in support of the argument that market power in generation extends to short-term forwards. There have been short forward positions that have been covered by investment in new generation, however, this only applies to deliveries beyond 18 months or so (FERC 2002).

As an alternative model, we explore a physical market in which all demand shows up in the forward market (or that the market is cleared against an accurate forecast of the expected demand), and the forward price is determined using a ‘‘market clearing’’ condition. This case can be seen as a purely physical market, because in the presence of speculators who could arbitrage between forward and spot markets, such a system would not work.[18] This essentially relaxes the no-arbitrage condition, and provides generators possessing market power with the opportunity to indulge in intertemporal price discrimination, and extract a strategic premium in the forward market.

We analyze the following cases (a detailed description of each case follows):

Case A. Cost Based Economic Dispatch.

Case B. Single-settlement—Centralized Market.

Case C. Two-settlement System for Electricity—No Arbitrage.

Case D. Two-settlement System for Electricity—Market Clearing.

Case A. This is the welfare maximizing[19] outcome and will be the solution to:

$$\text{(A)} \qquad \begin{aligned} p_i &= MC(q_i) \text{ for all nodes with generation}, i. \\ p_j &= p_j(D_j) \text{ for all demand nodes, } j. \\ \sum_i q_i &= \sum_j D_j. \\ \sum_i \beta^c_{a,i} q_i - \sum_j \beta^c_{a,j} D_j &= \bar{f}^c_a \text{ for constrained line } a. \\ p_j &= p_i + \sum_a \beta_{a,i} \lambda^c_a \text{ for all nodes } i \text{ and hub } j \ (i \neq j), \end{aligned} \tag{1}$$

where, p_i, is the price at node i (we suppress the superscript for the state on energy prices and quantities), q_i is the production at node i (it is assumed that each firm has a single plant), D_j is demand at node j, λ_{ac} is the multiplier associated with link a[20] in state c, $c \in \{1, 2\}$ an index set of states, $\beta_{a,i}$ is the power transfer distribution factor or the amount

18 This also assumes that demand behaves non-strategically.

19 As stated above, we use the sum of consumer and producer surpluses as a welfare measure.

20 In our examples, we assume that only the line between nodes 1 and 2 is congested.

of power that will flow over this line when 1 unit of power is transferred from node i to a reference node, and $\bar{f}_a^c$ is the capacity of this link in state c. Convexity restrictions on the demand and cost functions yield unique outcomes.

Case B. In this case, we simulate a centralized market outcome in a single-settlement system with generators behaving à la Cournot (see Hobbs 2001). In a centralized market model, the system operator sets generation and demand so as to maximize gains from trade, and transmission prices are set equal to the difference in nodal prices. We assume that generators take transmission prices as given or that generators do not consider the influence of their decisions on transmission prices. An equilibrium of this single-settlement system can be paralleled to an equilibrium of the following two stage game. In the second stage of this game, the system operator arbitrages any differences in energy prices that are not based on cost, such that in the resulting equilibrium, there is no spatial discrimination in energy prices, i.e., the price difference between two nodes is exactly equal to the transmission charge for transferring energy between the two nodes. In the first stage, generators anticipate this arbitrage and compete in a Cournot–Nash manner. Each generator will solve the following constrained optimization problem in a centralized market:

$$\text{(B)} \qquad \begin{aligned} &\max_{q_i, D_1, \ldots, D_n, p_1, \ldots, p_n} \Pi_i = p_i q_i - C_i(q_i), \\ &p_j = p_j\ (D_j) \quad \text{for all nodes } j, \\ &q_i + \sum_{k \neq i} q_k = \sum_j D_j, \\ &p_j = p_i + \sum_a \beta_{a,i}^c \lambda_a^c \quad \text{for all nodes } i \text{ and hub } j\ (i \neq j). \end{aligned} \tag{2}$$

Here λ_a^c is to be interpreted as the multiplier associated with the system operator's problem which the generators take as given, i.e., it is a parameter of the above optimization problem. The equilibrium for the game can be solved by collecting the two first order necessary conditions (FONCs) along with the constraints of the problem, and the following set of inequalities and complementary slackness conditions from the system operator's problem:

$$\text{(Ba)} \qquad \begin{aligned} &\sum_i \beta_{a,i}^c q_i - \sum_j \beta_{a,j}^c D_j \leq \bar{f}_a^c \text{ for all } a, \\ &\left(\sum_i \beta_{a,i}^c q_i - \sum_j \beta_{a,j}^c D_j - \bar{f}_a^c \right) \lambda_a^c = 0 \text{ for all } a. \end{aligned} \tag{3}$$

In the case with quadratic demand and cost functions, the equilibrium problem is a linear (mixed) complimentarity problem (LCP) (mixed due to the equality constraints). Convexity restrictions on the demand and cost functions yield unique equilibrium points.

Case C. In this case, we assume that the system operator operates a single forward market for all demand within the zone with a delivery requirement on forward transactions. This implies that all transactions that are dispatched in the spot market are charged the spot transmission charge (see Chao et al. 2000b). This provides incentives for generators to avoid what is called a DEC game in markets where such aggregation is done in the forward market, e.g., the now defunct California PX market (see Kamat and Oren 2002 for an analysis of cases with residual spot markets, i.e., markets where the spot transmission charge only applies to the part of the forward transaction cleared in the spot market). In a centralized market, it becomes necessary to decide on a hub which establishes the spot transmission charge. Keeping in line with our earlier assumption for the settlement price for a forward contract, we use the demand-weighted average price as the hub price.[21] Generators solve the following optimization problem in the spot market:

$$
\text{(C)} \qquad
\begin{aligned}
&\max_{q_i, D_1, \ldots, D_n, p_1, \ldots, p_n} \Pi_i = p^f f_i + p_i(q_i - f_i) - C_i(q_i) - f_i(p_{\text{hub}} - p_i),\\
&p_j = p_j\,(D_j) \text{ for all nodes } j,\\
&q_i + \sum_{k \neq i} q_k = \sum_j D_j,\\
&p_j = p_i + \sum_a \beta^c_{a,i} \lambda^c_a \quad \text{for all nodes } i \text{ and hub } j \ (i \neq j),\\
&p_{\text{hub}} = \sum_j \frac{p_j D_j}{\sum_k D_k}.
\end{aligned}
\tag{4}
$$

Where p^f is the forward price and f_i the forward position of generator i. Again, λ^c_a is a parameter in the above problem. As the hub price introduces nonlinearity in the equilibrium conditions, the resulting spot market equilibrium problem is a non-linear LCP. In order to calculate an equilibrium of the two-settlement system, we employ the notion of a subgame perfect Nash equilibrium (SPNE) (see Fudenberg and Tirole 1991). This says that in period 1, generators will correctly anticipate the reactions of all the agents moving in period 2. The generators will therefore solve an expected profit maximization problem in period 1 (we assume that generators are risk-neutral), subject to equilibrium constraints in the forward market, if any, and correctly anticipating the optimal values from the spot optimization problem, i.e., the non-linear LCP will appear as a constraint in the optimization problem solved by generators in period 1.[22] We conduct a grid search to determine the optimal forward positions by numerically tracing reaction functions in the forward market.

Case D. This case is the formulated as Case C above except that the forward price is determined by a market clearing condition, i.e., $p^f = p(f_1 + f_2)$, where $p(\cdot)$ is the aggregate demand function, and f_1 and f_2 are forward positions of respective generators.

21 While it is not common that forward commodity contracts are settled at a floating price (as opposed to the price at a fixed delivery point), this is common practice in electricity markets, e.g., the forward contract at the PJM Western hub is settled at a weighted price based on 100 nodal prices.

22 In the general case, the generator's problem will be non-convex due to the complementary slackness conditions imposed in the spot market equilibrium. As mentioned earlier, if congestion patterns are easily predicted these can be dropped.

4. Two-Node Example

Consider the example in figure 1 with a single generator at each node of a simple two-node network. Cost and demand functions are linear as indicated at each node. We assume there are two states of the world, one in which the network does not have any transmission constraints, and the other where the capacity of the line joining nodes 1 and 2 is K MW. We model the two states using a random variable which takes two values θ (a large positive number) and 0 with probability r and $1 - r$, respectively (θ is assumed to be large enough so that the transmission line between the two nodes is not congested in the cases we consider). The generator at node 1 is assumed to be low cost, and could run at output levels that the transmission line would not be able to sustain in the state of the world where this capacity limit is binding (see table 1 for data).

4.1. No Congestion (Allaz and Vila 1993)

We first analyze an example with no congestion in the spot market (see Allaz and Vila 1993).[23] This will give us a point of departure from the literature, and a basis for comparing how the presence of transmission constraints affects behavior in two-settlement systems with imperfect competition. We assume symmetric demands for the two nodes in the system.

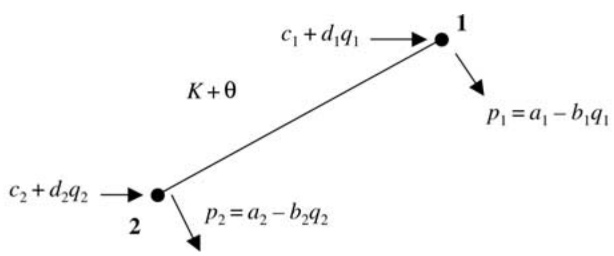

Figure 1. A simple two-node network.

Table 1. Parameter Values for Two-node Example	
Parameter	Value
a_1, a_2	100
b_1, b_2	2
c_1, c_2	10
d_1	1
d_2	4
K	3
θ	Large
r	Variable

23 This is the case when $r = \Pr\{\theta = 0\} = 0$.

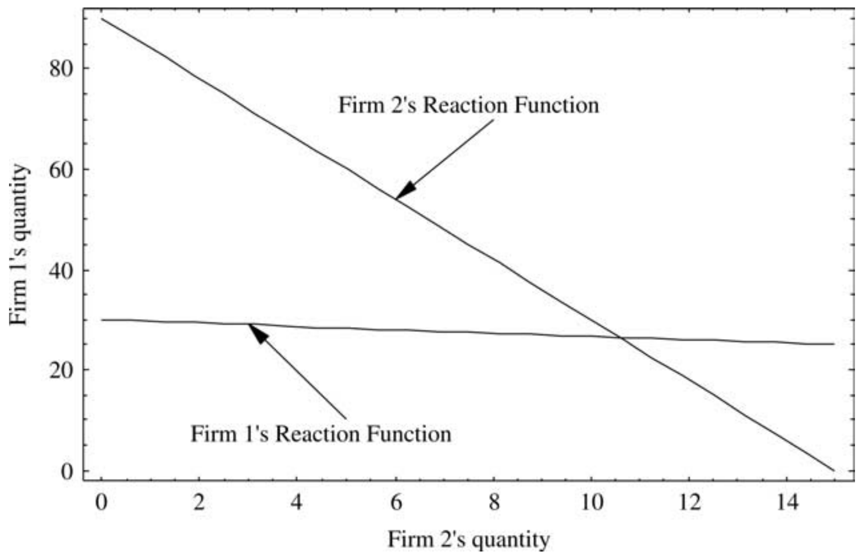

Figure 2. Reaction functions for case B (no transmission constraints).

Case A. In the optimum dispatch, marginal costs for both generators are equal to price which is determined by clearing the aggregate market for the two nodes (see equation set (1)). This gives the maximum surplus that can be generated in this market.

Case B. In the single-settlement case, generators compete in a Cournot–Nash game. As there are no transmission constraints, each generator solves an simple unconstrained optimization problem (see problem (2) after substituting the market clearing constraint into the objective). The standard first order condition of equating marginal revenues, with respect to the residual demand curve seen by a generator, to marginal costs applies directly. These can be expressed as:

$$p(q_i + q_j) + q_i p'(\cdot) = C_i'(q_i) \qquad \forall i,\ j = 1,2\ (j \neq i), \tag{5}$$

where $p(q)$ is the aggregate inverse demand function.

These equations can be used to derive the reaction functions of the two generators in this market, i.e., the optimal production quantity of a generator as a function of the other generator's production quantity. The equilibrium quantities can be calculated as the point of intersection of the two reaction functions. For our case of demands and marginal costs which are linear in quantity, the reaction functions are also linear, and will therefore result in a unique equilibrium (see figure 2).[24]

24 For nonlinear demand functions, there may be cases (such as with convex demand functions) that one may have multiple equilibria in the spot market.

The first order conditions (5) can be rewritten as:

$$\frac{p(\cdot) - C_i'(q_i)}{p(\cdot)} = \frac{s_i}{\varepsilon} \quad \text{for} \quad i = 1, 2, \tag{6}$$

where $s_i = q_i/(q_i + q_j)$, is firm i's share of total production, and $\varepsilon = -(1/p'(\cdot))(p(\cdot)/q)$ is the elasticity of aggregate demand at the aggregate production quantity, q. The left hand side is called the Lerner index for firm i.

Case C. The two-settlement system case is solved as a two period game. In the second period, generators will maximize profits given their forward commitments. The first order conditions in this case will be a modified version for those of the Cournot case (see problem (2)):

$$p(q_i + q_j) + (q_i - f_i)p'(\cdot) = C_i'(q_i) \quad \text{for} \quad i, j = 1, 2 \ (j \neq i), \tag{7}$$

where f_i is the firm's forward position. Another way of deriving first order conditions is by marginal analysis, which looks at the benefit and cost of producing an additional unit setting the base level to the optimal production quantity:

$$\underbrace{p(q_i + q_j) - C_i'(q_i)}_{\text{Marginal Benefit}} + \underbrace{(q_i - f_i)p'(\cdot)}_{\text{Marginal Cost}} = 0 \quad \text{for} \quad i,\ j = 1, 2 \ (j \neq i). \tag{8}$$

This says that at the margin, the benefit of producing an extra unit, the price-cost margin $p(\cdot) - C'(\cdot)$, should be equated to the externality cost of producing that unit which is the decrease in revenues from all infra-marginal units affected, $(q_i - f_i)p'(\cdot)$. As generators are expected to take short positions in the forward market, price cost margins in a two-settlement system will be smaller than in the Cournot case. Thus, forward commitments result in greater production in the spot market, and have the potential to increase the realized surplus as compared to the single-settlement case. This can be seen in the plot of the reaction functions which go outward for larger forward commitments (see figure 3).

In a similar manner as equation (6), the first order conditions can be expressed as:

$$\frac{p(\cdot) - C_i'(q_i)}{p(\cdot)} = \frac{s_i'}{\varepsilon} \quad \text{for} \quad i = 1, 2, \tag{9}$$

where $s_i' = (q_i - f_i)/(q_i + q_j)$, is generator i's adjusted share of total production. Therefore, the firm will behave as if it has a smaller share in the spot market than it actually has, and will be a more aggressive competitor, because it can free-ride on other participants in the market who share the burden of a price decrease.

In the forward market, the generators will solve an optimization problem with forward positions as decision variables. They will take into account how their forward position affects the equilibrium in the spot market (this can be done by computing the forward market equilibrium numerically, where the spot market equilibrium is solved as a

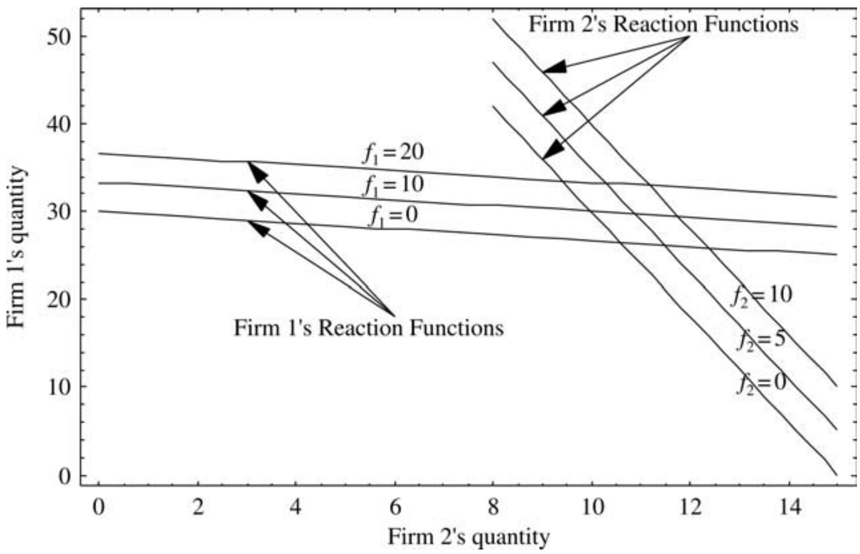

Figure 3. Reaction functions in the spot market for case C (no transmission constraints).

subproblem).[25] As in Allaz and Vila (1993), we assume that speculators arbitrage between spot and forward prices, therefore the forward price will be equal to the spot price. Writing the first order condition in the benefit-cost framework we get:

$$\underbrace{(p(\cdot) - C_i'(\cdot))q_i'(\cdot)}_{\text{Marginal Benefit}} + \underbrace{q_i p'(\cdot)(q_i'(\cdot) + q_j'(\cdot))}_{\text{Marginal Cost}} = 0 \quad \text{for} \quad i,j = 1,2\ (j \neq i). \tag{10}$$

This says that the marginal benefit of hedging an extra unit in the forward market is the price-cost margin in the spot market for this level of forward positions multiplied by the sensitivity of the spot quantity to a unit change in this generator's forward position. The externality cost is the loss of revenue in the spot market from a decrease in spot price induced by the unit increase in the forward position (which is reduced through the increase in generator's own production quantity as well as its competitor's because equilibrium spot production quantities are a function of both forward positions). The entire quantity traded on the spot market, q_i, is affected due to equality between spot and forward prices imposed by the no-arbitrage condition (see figure 4 for a plot of the reaction functions). One can group terms to get:

$$((p(\cdot) - C_i'(\cdot)) + q_i p'(\cdot))q_i'(\cdot) + q_i p'(\cdot)q_j'(\cdot)) = 0 \quad \text{for} \quad i,\ j = 1,2\ (j \neq i). \tag{11}$$

The first term in brackets is the Cournot first-order condition which will evaluate to zero at

25 This assumes that forward positions are observable.

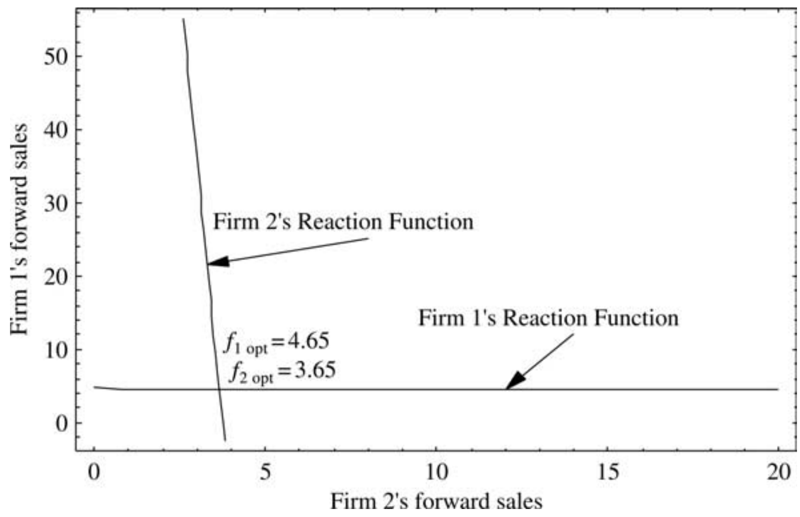

Figure 4. Reaction functions in the forward market for case C (no transmission constraints).

a forward position of zero. The second term evaluates to a positive value due the ''strategic substitutes effect'' (see the discussion in section 2.2.1), i.e., q_j' is negative. This means that generators will want to take positive (short) positions in order to commit to more aggressive behavior in the spot market, and this behavior is driven entirely by the fact that production quantities are strategic substitutes. As both generators take short positions, a prisoner's dilemma type of outcome occurs and both generators have lower profits and social welfare increases. A striking feature of the forward market equilibrium is that the aggregate forward position is a small fraction of the total spot production quantity (less than 20%).[26]

Case D. Given that a no-arbitrage condition in a two period setting produces a small quantity of forward trading, in the current set of cases we explore the implications of relaxing the no-arbitrage condition. Electricity markets usually have physical markets that run in parallel to financial markets, and these are run for only a few periods. Given that the market is non-competitive, the financial market is likely to be illiquid due to the fact that spot market outcomes can be manipulated by generators participating in the physical market. In the physical market, a market clearing mechanism is usually used to determine price. We model this by assuming that all of the demand shows up in the forward market and is aggregated to determine the forward price.[27] This will result in a lower elasticity of

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26 This is mainly because we only consider only two periods. Allaz and Vila (1993) show that as the number of trading periods increase to infinity all of the spot production quantity is hedged in forward contracts, and the resulting spot market outcome, corresponds to the competitive outcome. Allaz and Vila (1993), however, do not quantify the proportion of the spot market quantity hedged in the forward market as the number of periods increase. Although, we use a specific example to quantify this proportion we have performed sensitivity analysis on the cost function and demand parameters that shows that the addition of a single trading period produces a relatively small quantity of forward trading.

27 This can also be interpreted that the forward market is cleared using an accurate forecast of the demand.

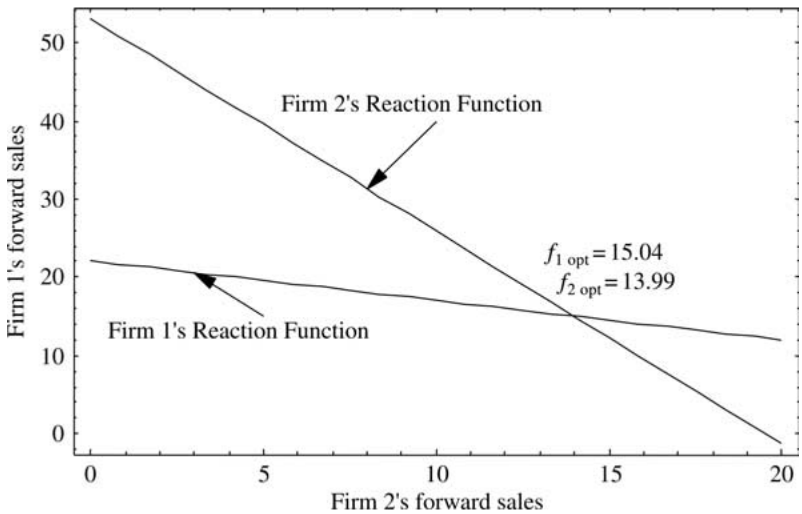

Figure 5. Reaction functions in the forward market for case D (no transmission constraints).

demand in the forward market than the previous case in which the forward demand curve is infinitely elastic due to the imposition of the no-arbitrage condition. The lower elasticity gives generators an extra degree of freedom to extract surplus from consumers by raising forward prices. A larger part of demand will now be met by forward commitments due to the market clearing mechanism being used in the forward market, and this will result in more aggressive behavior in the spot market on the part of generators. It remains to be seen how the more aggressive behavior in the spot market as a result increased forward trading will affect total surplus generated in this market.[28]

In this case, the two generators have the same incentives in the spot market as compared to the ''No arbitrage'' case. However, in the forward market the generators can directly influence the forward price by changing their positions. There is an additional term in the first order condition reflecting the difference between forward and spot prices:

$$\underbrace{(p^f - p(\cdot)) + (p(\cdot) - C_i'(\cdot))q_i'(\cdot)}_{\text{Marginal Benefit}} + \underbrace{q_i p'(\cdot)(q_i'(\cdot) + q_j'(\cdot))}_{\text{Marginal Cost}} = 0 \quad \text{for} \quad i,\ j = 1, 2\ (j \neq i). \tag{12}$$

The equilibrium results in a larger proportion of the spot production quantities being hedged in the forward market (see figure 5). As a result, spot production quantities are higher for both firms as both generators take larger short positions in the forward market.

28 One can argue, that given an infinite number of trading periods where such a market-clearing mechanism is used to clear the forward market, generators can extract the entire surplus of the consumers by offering a set of decreasing prices such that they capture the entire surplus of consumers trading in any given period. The resulting quantity produced in the spot market will be the competitive outcome quantity, however, no residual demand will be traded in the spot market.

4.2. Transmission Constraints

We now consider the case where the probability that the transmission line will have a constraining capacity is positive, i.e., there will be two states of nature in the second period, one in which the spot market is unconstrained, and the other where the transmission line between the two nodes will have a capacity of K units. We assume node 2 as the hub node for determining spot prices, therefore the shift factors will be $\beta_{1-2,1} = 1$ and $\beta_{1-2,2} = 0$ for nodes 1 and 2, respectively.[29] We illustrate the impact of congestion by analyzing how the reaction functions and equilibria change as a function of congestion. Numerical results are reported for a probability of congestion, $r = 0.05$.[30]

Case A.

Unconstrained State: Results are the same as the Allaz–Vila (AV) example.

Constrained State: When the transmission line between nodes 1 and 2 has a small enough capacity, prices at the two nodes will not be equal. At node 1, where the cheaper generator is located, price is set such that the excess supply at this price is equal to the capacity of the transmission line. Similarly, at node 2 the price is set such that the excess demand at this price is equal to the imports from node 1, i.e., K units. The difference in prices is the transmission tariff charged to exports from node 1 (see equation set (1) with $\bar{f}_{1-2} = K$).

Case B.

Unconstrained State: Results are the same as the AV example.

Constrained State: As mentioned before, in solving for the spot market equilibrium, we assume that the generators do not game the transmission system, i.e., they are price takers in the transmission market, and reveal their true willingness to pay for transmission services. We solve for this equilibrium assuming that the transmission link will be constrained in the direction $1 \rightarrow 2$ (cheap to dear).[31] This implies that the residual demand curve observed by the cheap (dear) generator is the original demand schedule at that node shifted right (left) by the capacity of the transmission link, K. The residual demand schedules that the generators face will therefore be insensitive to the quantity produced by the other generator (see figure 6). The elasticity of demand in the residual market will be smaller in this case as the market is now disaggregated. Equilibrium prices will be lower at the exporting node and higher at the importing node as compared to the unconstrained state.

Case C. As in the AV example, we solve the two-settlement cases as two period games. There will now be two states of the world in the spot market. In this case, we assume that the commodity price being traded in the forward market is the demand-weighted average spot price. In the presence of risk-neutral speculators who can arbitrage between the two

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29 A shift factor represents the fraction of power that flows over a particular transmission line if 1 MW of electricity is sent from the node in question to the hub node.

30 We assume that intra-zonal congestion will be present in 200 of about 4,000 peak hours, which gives the average case. The probability of congestion can be substantially higher if there is an impending derating.

31 For larger networks, the equilibrium can be formulated as a complementarity problem (see Hobbs, 2001).

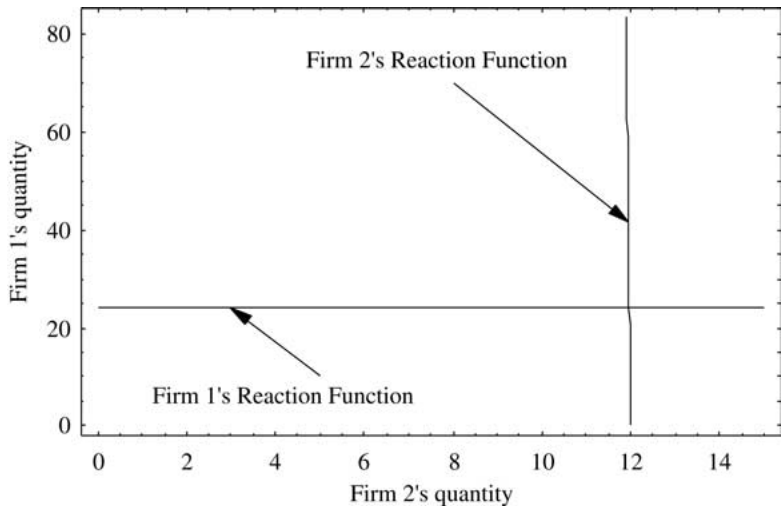

Figure 6. Reaction functions in the spot market for case B (constrained state).

markets, the forward price will converge to the expected demand-weighted spot price (assuming zero interest rates). *Spot Market—Unconstrained State*: Generators will have the same incentives as AV example (figure 3).

Spot Market—Constrained State: We use the first order conditions of Problem C to plot the reaction functions for this case as a function of own forward positions (see figure 7). The hub price introduces nonlinearity in the reaction functions in this case. However, for a given spot production quantity of a competitor, the optimal spot production quantity of the generators is increasing in the generator's own forward position.

Forward Market: As the hub price introduces nonlinearity in the equilibrium conditions, we cannot solve for the equilibrium spot quantities and prices in terms of the forward positions analytically. To determine optimal forward positions, we conduct a grid search, and numerically trace the reaction functions in the forward market (see figure 8). The profit function for generator i is now:

$$\Pi_i^f = p^f f_i + E\{(q_i(\cdot) - f_i)p_i(\cdot) - C_i(q_i(\cdot))\}, \tag{13}$$

where the expectation is with respect to the random variable, θ, describing the state of the system (the system is in the constrained state with a probability r). The first order conditions in the forward market show that forward positions are declining in r, the probability of congestion:[32]

32 We do not calculate the optimal positions (which are negative) in this case as it is primarily our interest to show that they are not positive. Due to repetition, if generators have incentive to take long positions, such a system would not function effectively.

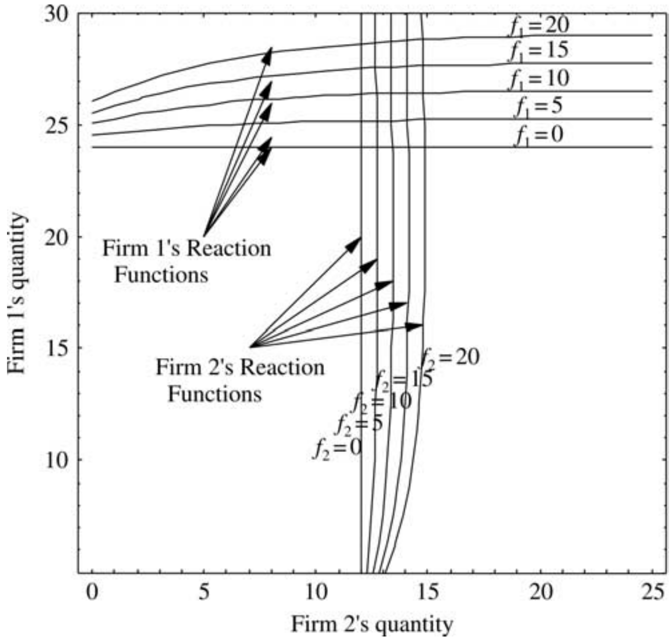

Figure 7. Reaction functions in the spot market for case C (constrained state).

$$\begin{aligned}
&\underbrace{(p^{noK}(\cdot) - C_i'(\cdot))q_i'^{noK}(\cdot) + q_i^{noK}p'^{noK}(\cdot)(q_i'^{noK}(\cdot) + q_j'^{noK}(\cdot))}_{\text{Original } FONCs} \\
&\underbrace{+\, r\big((p_i^K(\cdot) - C_i'(\cdot))q'i^K(\cdot)) - (p^{noK}(\cdot) - C_i'(\cdot))q_i'^{noK}(\cdot)\big)}_{\text{Marginal Benefit}} \\
&\underbrace{+\, r\big(q_i^K p_i'^K(\cdot)(q_i'^K(\cdot) + q_j'^K(\cdot)) - q_i^{noK}p'^{noK}(\cdot)(q_i'^{noK}(\cdot) + q_j'^{noK}(\cdot))\big)}_{\text{Marginal Cost}} \\
&= 0 \quad \text{for} \quad i,\ j = 1, 2\ (j \neq i). \qquad (14)
\end{aligned}$$

Case D.

Spot Market: Generators will have the same incentives as AV example (figure 3).

Forward Market: The qualitative impact of congestion is similar to the previous case, in that total forward positions decrease as the probability of congestion increases. This seems to point to a spillover effect, in that there seems to be an indirect value to a more reliable network in terms of its ability to reduce market power. Even though congestion is rare, the possibility that a line may be congested produces incentives to reduce forward coverage, and thus, reduces the ability of the forward market to mitigate market power in the normal, i.e., uncongested state.

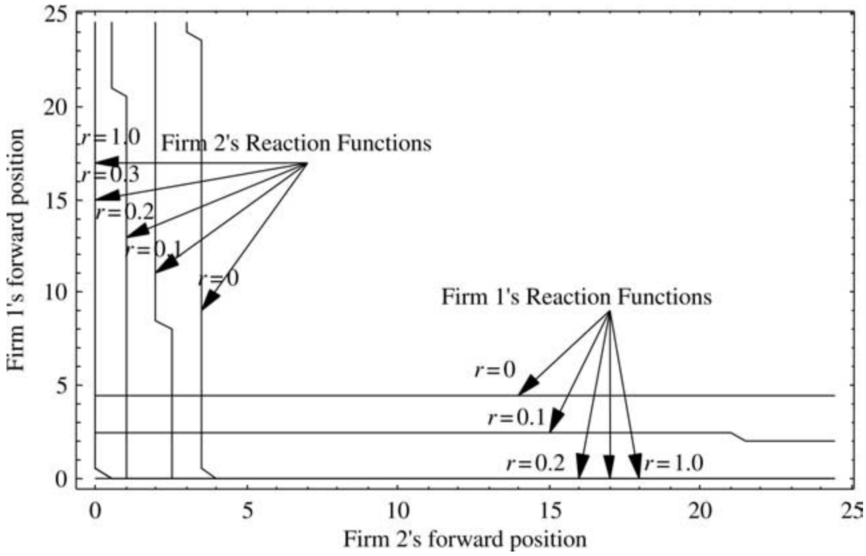

Figure 8. Reaction functions in the forward market for case C for various probabilities of congestion, r.

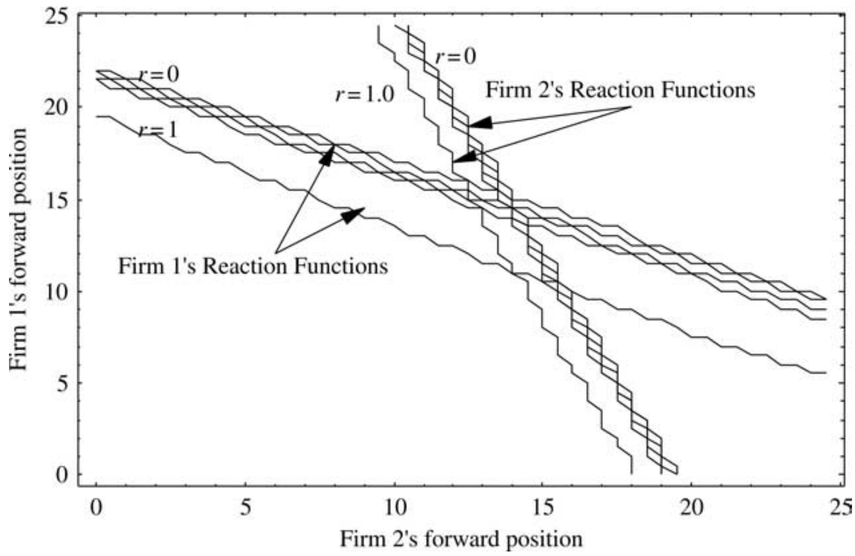

Figure 9. Reaction functions in the forward market for case D for various probabilities of congestion, r.

4.3. A Numerical Example

In this section, we present some numerical results for the two node network in figure 1 (see table 1 for parameter values). The probability of congestion is assumed to be 0.05 (see the Appendix for results). The optimal dispatch results in welfare levels of \$2,250 per hour and \$2,106 per hour in the unconstrained and constrained state, respectively (see column 4 of table 2 for welfare levels). The single-settlement centralized dispatch results in welfare levels that are lower than the optimal dispatch in the amount of 7.8% and 5.1%, in the unconstrained and constrained state, respectively. Two-settlement systems are generally known to lead to more aggressive behavior on part of generators in the spot market, and it is expected that the two-settlement systems will make up some of the welfare loss due to market power. We observe that for this level of congestion, two-settlement systems continue to be welfare enhancing, reflecting the no congestion (AV) case. For the ''no-arbitrage'' case, consumers benefit because of the higher spot production to the detriment of generators, as in previous literature (see column 3 of table 2 for consumer surplus levels, and column 1 of table 2 for generator profits). Profits for the generators show the prisoner's dilemma effect at work. Specifically, the combined profit of the generators drops from \$1,387 per hour for case B to \$1,365 per hour for Case C. The ''market clearing'' case has a higher welfare increase due to larger coverage in forward contracts, however, consumer surplus is lower as compared to the ''no-arbitrage'' case because of the intertemporal price discrimination. Producers are able to extract as much as 29% of consumer surplus in Case D as compared to Case C.

In the optimal dispatch, price is \$50 per MWh in the unconstrained state (see table 3 for prices in the spot and forward market). In the constrained state, spot price at node 1 is \$42 per MWh, while at node 2 it is \$66 per MWh. In comparison, the price in the unconstrained state for case B is \$63 per MWh, while it is \$58 per MWh and \$70 per MWh at nodes 1 and 2, respectively in the constrained state. In the ''no-arbitrage'' two-settlement case, prices in the unconstrained state are about \$1 lower, while they are \$6 lower in the ''market clearing'' two-settlement case than for the single-settlement case. These results are also driven primarily by the amount of forward coverage which is much larger in the ''market clearing'' case. The forward prices in the ''market clearing'' case is \$71 per MWh, with expected spot prices averaging \$57 per MWh.[33] While this difference seems quite large, and almost unsustainable in a repeated market, price differentials of a few dollars have been observed in the first year of the day-ahead and real-time California markets (Borenstein et al. 2001).[34]

The generation market in the example is asymmetric with 80% of spot market production at the exporting node for the optimal dispatch (see column 4 of table 4 for generation levels; table 4 also shows sales and transmission flow levels). Demand in the constrained state is 8% lower as compared to the unconstrained state (this is the sum of the

33 The magnitude of the difference in forward and spot prices in the ''market clearing'' case is related to our assumptions regarding the slope (elasticity) of the demand functions. For a three-node example with different data (not reported here), price differentials are smaller.

34 Borenstein et al. calculate differentials between spot and day-ahead prices, so if day-ahead prices are higher their differentials are negative. This differential can also be interpreted as a risk premium. Interestingly, they also report positive price differentials of a few dollars in the Fall of the first year; these are not statistically significant in the second year. They also point out to inefficiencies that can come about in the system due to predictable congestion across an inter-zonal interface (inter-zonal congestion is priced in the day-ahead market and an outcome of no congestion in the day-ahead market is a reflection of expectations of market participants, whereas in our model intra-zonal congestion is ignored as part of the market design).

two parts of column 1). The generator at the exporting node is primarily responsible for exerting market power, reducing production by 33% for the single-settlement case. An interesting result for the two-settlement cases is that the generator at the importing node produces at higher levels than in the optimal dispatch case, because of its commitment in the forward market. This implies that though generators have incentives to be more aggressive in a two-settlement system, some of the aggression is misplaced, and less efficient generators may be producing at higher levels than is socially optimal.

As mentioned above, a striking result is that in the ''no-arbitrage'' case, having one forward period yields about 17% contract coverage (see table 5 for forward sales). The ''market clearing'' case, on the other hand, has contract coverage of around 67%. This points to the fact that in the presence of market power, the strategic incentives that generators have to contract in short-term forward markets play a big role in the outcome of these markets, perhaps dominating the risk-sharing aspects of these markets. One other significant result not seen in the numerical results is that generators have incentive to go long in the forward market as the probability of congestion increases. Welfare levels are usually reduced to levels lower than the single-settlement case in such situations.

We have done numerical studies with a three-node example with a single constrained line and two generators. We find that the qualitative results that we report here—such as the small proportion of forward contracting in the ''no-arbitrage'' case, and the increase in contract coverage when this assumption is relaxed—go through for such cases with loop-flow (see Kamat and Oren 2002).

5. Concluding Remarks and Future Work

In this paper, we model and analyze, in the presence of network uncertainty and market power, several electricity market designs currently adopted or proposed in the U.S. Using the centralized dispatch single-settlement system as a benchmark, we analyze and compare market outcomes for a two-settlement system with a single forward contract over simple two-node systems. We find that welfare impacts of two-settlement systems are highly sensitive to the probability that a network contingency reduces the transmission capacity of an important line in the network. Using a duopoly model, we show that this sensitivity comes from two effects. The first effect is asymmetric, and is due to the presence of transmission constraints. Price cost margins are lower at the exporting node in the constrained state as compared to the unconstrained state, and vice versa for the importing node. The second effect is a combination of the fact that markets are segregated in the constrained state and the lack of the ''strategic substitutes effect'' (see Bulow et al. 1985) in that state. The combined effect of these factors is that for even small probabilities of congestion, forward trading may be substantially reduced, and the market power mitigating effect of forward markets (as shown in Allaz and Vila 1993) may be nullified to a great extent. This points to an indirect value to a more reliable (lower probability of congestion or increased capacity) network in terms of its ability to reduce market power. Even though congestion is rare, the possibility that a line may be congested produces incentives to reduce forward coverage, and thus, reduces the ability of the forward market to mitigate market power in the normal, i.e., uncongested state.

In our analysis, we find that the standard assumption of ''no-arbitrage'' across forward and spot markets leads to very little contract coverage even in the no congestion case. This seems to be at odds with empirical evidence that there is substantial contract coverage in electricity markets. In providing an alternative view of the market, we explore the implications of relaxing the ''no-arbitrage'' assumption, and assume that all of the demand shows up in the forward market and is aggregated to determine the forward price using a ''market clearing'' condition. This essentially gives the generators an extra degree of freedom to extract surplus from consumers. This also re-establishes the incentives for generators to take short positions in the forward market, and we find higher levels of contract coverage in these cases.

In our examples, we considered a single-zone system and therefore ignored the impact of transmission contracts in the market outcomes. As the design of transmission contracts has been a topic of active debate over the past few years, and the impact of network uncertainty is an important component of the debate, extending our model to a multi-zonal system with pricing of inter-zonal congestion in the forward market seems to be a fruitful area for future research. Another direction that can be explored is the effect of repetition. Electricity auctions are repeated on a daily basis, and this may give generators a opportunity to participate in complex strategic moves that may lead to a much larger set of possible equilibria, or disequilibrium behavior which has been observed in experiments involving finitely repeated prisoner's dilemma games (Rothkopf 1999).

Appendix

Table 2. Welfare Measures

State	Profit ($/hr) (1)		Grid Owner Rev ($/hr) (2)	Consumer Surplus ($/hr) (3)	Social Welfare ($/hr) (4)
	Gen. 1	Gen. 2			
Unconstrained					
Single-settlement					
Opt. Dispatch (A)	800.0	200.0	0.0	1,250.0	2,250.0
Centralized (B)	1,051.0	336.3	0.0	686.7	2,074.0
Two-settlement					
No Arbitrage (C)	1,040.5	324.5	0.0	738.8	2,103.8
Market Clearing (D)	1,183.7	472.0	0.0	520.2	2,175.8
Constrained					
Single-settlement					
Opt. Dispatch (A)	512.0	392.0	72.0	1,130.0	2,106.0
Centralized (B)	864.0	432.0	36.0	666.0	1,998.0
Two-settlement					
No Arbitrage (C)	841.6	426.1	38.6	715.4	2,021.8
Market Clearing (D)	953.9	589.6	46.1	487.6	2,077.2

Table 3. Prices in the Spot and Forward Markets

	Spot Market			Forward Market	
	Delivered Price ($/MWh) (1)		Trans. Price ($/MWh) (2)	Forward Price ($/MWh) (3)	
State	Node 1	Node 2	Link 1–2	Node 1	Node 2
Unconstrained					
Single-settlement					
Opt. Dispatch (A)	50.0	50.0	0.0	—	—
Centralized (B)	62.9	62.9	0.0	—	—
Two-settlement					
No Arbitrage (C)	61.6	61.6	0.0	61.6	61.6
Market Clearing (D)	56.9	56.9	0.0	71.0	71.0
Constrained					
Single-settlement					
Opt. Dispatch (A)	42.0	66.0	24.0	—	—
Centralized (B)	58.0	70.0	12.0	—	—
Two-settlement					
No Arbitrage (C)	56.3	69.2	12.9	61.6	61.6
Market Clearing (D)	50.8	66.1	15.4	71.0	71.0

Table 4. Generation, Sales and Transmission

	Quantity Demanded (1)		Sales by Firm 1 (2)		Sales by Firm 2 (3)		Generation (4)		Flow (5)
State	Node 1	Node 2	Node 1	Node 2	Node 1	Node 2	Firm 1	Firm 2	1–2
Unconstrained									
Single-settlement									
Opt. Dispatch (A)	25.0	25.0	40.0	0.0	0.0	10.0	40.0	10.0	15.0
Centralized (B)	18.5	18.5	26.5	0.0	0.0	10.6	26.5	10.6	7.9
Two-settlement									
No Arbitrage (C)	19.2	19.2	27.5	0.0	0.0	10.9	27.5	10.9	8.3
Market Clearing (D)	21.6	21.6	30.9	0.0	0.0	12.2	30.9	12.2	9.4
Constrained									
Single-settlement									
Opt. Dispatch (A)	29.0	17.0	32.0	0.0	0.0	14.0	32.0	14.0	3.0
Centralized (B)	21.0	15.0	24.0	0.0	0.0	12.0	24.0	12.0	3.0
Two-settlement									
No Arbitrage (C)	21.8	15.4	24.8	0.0	0.0	12.4	24.8	12.4	3.0
Market Clearing (D)	24.6	16.9	27.6	0.0	0.0	13.9	27.6	13.9	3.0

Table 5. Forward Sales

State	Forward Quantity Demanded (1)		Forward Sales by Firm 1 (2)		Forward Sales by Firm 2 (3)	
Two-settlement						
No Arbitrage (C)	—	—	3.5	0.0	0.0	3.0
Market Clearing (D)	14.5	14.5	15.0	0.0	0.0	14.0

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