Border Flow Rights and Contracts for Differences of Differences: Models for Electric Transmission Property Rights

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***Abstract*—In this paper, a property rights model for electric transmission is proposed and its properties analyzed. The proposed rights, called "border flow rights," support financial hedging of transmission risk and merchant transmission expansion through associated financial rights, called "contracts for differences of differences." These financial rights allow for forward trading of both energy and transmission by a unified exchange, avoiding the bifurcation in current markets between decentralized long-term energy trading and centralized long-term transmission trading. Such long-term trading can help to support the financing of both generation and transmission assets. We consider incentive properties of such a right in the absence of lumpiness, economies of scale, and market power.**

***Index Terms*—Electricity market, energy and transmission trading, financial transmission rights, property rights, transmission investment.**

I. Introduction

THIS paper builds on recent work by Gribik *et al.* [1], [2] that describes long-term property rights for transmission expansion, on provisions in the Australian electricity code [3], and on discussions of transmission in [4]–[10]. We propose a property rights model for existing and new transmission investment, called "border flow rights." By a property rights model for transmission, we mean a definition of an underlying revenue stream that accrues to the owner of a transmission line. Such a property rights model would provide an alternative for transmission regulation compared to current approaches such as rate-of-return regulation and performance-based ratemaking [11].

Under a basic implementation of the border flow rights model, the owner of a transmission line or lines is paid at the locational marginal price for energy that it delivers to the rest of the system and pays at the locational marginal price for energy that it receives from the rest of the system. The border flow rights model therefore values transmission by its contingency-constrained transport of lower value energy to locations having higher value energy.

Similar proposals have been critically considered in the literature before [4]–[10]. We re-visit such proposals and show that border flow rights provide an approximation to efficient marginal incentives for transmission expansion funded by coalitions of beneficiaries in the absence of lumpiness, economies of scale, and market power. While the assumptions of the absence of economies of scale and market power may be strong, particularly in the context of requiring coalitions of beneficiaries to form, we believe that the analysis is valuable because it clarifies the underlying assumptions and illustrates the incentives.

The basic formulation can also be expanded to value transport of real and reactive power and transport of real and reactive reserves. (See [12] for a development that includes both real and reactive power.)

Border flow rights accommodate trading of financial transmission congestion hedging instruments called "contracts for differences of differences" (CFDDs). Trading based on CFDDs is reminiscent of "contract path" transactions [13] but, unlike the contract path mechanism, incorporates Kirchhoff's laws and represents contingency constraints. CFDDs can be arranged between parties analogously to "contracts for differences" (CFDs) that are used to hedge locational marginal price variation at a given location [9, Section 3], [14, Section 3-2.1].

CFDDs define an alternative to "financial transmission rights" (FTRs) [13], [14, Chapters 5-9] that, in principle, can be traded without a central exchange. Trading of CFDDs is unlike the auctioning of FTRs in current markets that *requires* the independent system operator (ISO) to be intimately involved in the forward trading of transmission in order to guarantee "revenue adequacy" for the ISO [13, Appendix], [14, p. 439]. In contrast, the ISO need not be involved in trading of CFDDs because revenue *neutrality* for the ISO is guaranteed by the border flow rights model. This feature avoids the need for ISOs to be involved in FTR trading, contrasting fundamentally with current formulations of transmission property rights including that in Gribik *et al.* [1], [2].

In a basic sense, however, CFDDs are not novel since, as discussed in [6, Section IV.A], as alluded to in [15, Footnote 7], and as implemented through "basis spreads" in current markets [16], such financial rights can be synthesized from "long" and "short" energy positions. However, in the absence of an underlying revenue stream funded from congestion rental such as provided by border flow rights (or by FTRs), such synthesis exposes the underwriter to basis spread risk unless it is supported by an energy transaction that creates counterflow. Our contribution is to enable such financial instruments to be created from an underlying property right without speculative trades.

Although contracts for differences of differences can, in principle, be traded without an exchange, such an exchange is likely

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to help in matching providers of transmission services with users of transmission services, having a role that is somewhat more extensive than the role of a clearing-house for energy contracts. The exchange could facilitate trade of *both* forward transmission and forward energy contracts simultaneously over various timescales [17]. This would avoid the current separation of forward trading of transmission, involving ISOs, from forward trading of energy, which is generally not performed by ISOs except for day-ahead trading [18, Section 3].

In the context of energy, CFDs allow the coexistence of short-term offer-based economic dispatch by the ISO with longer term financial contracts to establish forward financial positions, without either constraining the other [14]. In contrast, currently implemented FTR mechanisms require the ISO to be intimately involved in the allocation and reconfiguration of forward transmission rights because congestion rental accruing to the ISO provides the revenue stream to fund the FTRs [13, Appendix]. Contracts for differences of differences, as proposed in this paper, would allow the ISO to instead focus solely on short-term dispatch, while long-term forward financial positions could be established without ISO involvement and without ISO financial exposure. This would allow independent system *operators* to focus on the operational issues associated with offer-based security-constrained economic dispatch, possibly including dispatch of both generation and transmission [19].

The organization of this paper is as follows. Section II contains a brief literature survey and contextualizes the goals of this paper. In Section III, we discuss the hedging of transmission and energy prices. In Section IV, we discuss the remuneration of transmission investment, with Section V presenting a simple two-bus example to illustrate the proposed revenue stream in the context of contingency constraints and varying generation offers. In Section VI, we consider a three-bus system from the literature to illustrate issues such as counterflow. Section VII discusses the proposed financial hedging mechanism. Alternatives for trading of the rights are sketched in Section VIII. Merchant transmission is discussed in Section IX, using the example from Section V to illustrate. Section X concludes. Further details, additional discussion including comparison to other types of transmission rights, and technical results are established in a technical reference available online [20].

II. Literature Survey and Goals

Financial transmission rights have been defined and discussed in several papers. For example, see: Hogan [13]; Chao and Peck [21]; Oren [22]; and Bushnell and Stoft [15]. Point-to-point financial transmission rights, as typically defined as being issued by the ISO, must be reconfigured centrally in order that the collection of rights satisfies the "simultaneous feasibility test" (SFT) [13, Appendix], [14, p. 439]. The first goal of the present paper is to remove the need for the ISO to be the issuer of rights, allowing for reconfiguration of transmission rights by an entity other than the ISO. This goal is achieved by defining transmission property rights in terms of an underlying revenue stream that depends only on the prices and flows resulting from offer-based security-constrained economic dispatch.

A second goal is to remove the risk to the ISO of revenue shortfall under transmission outage conditions. The risk is devolved to the owners of the transmission assets. To the extent that an outage affects the quantities of flows but not the prices, this provides the correct incentives to transmission owners. However, if an outage does affect prices significantly, then the incentives are not perfect. An example of this situation appears in [23, Section III.B.1].

The third goal of the present paper is to define a property right and associated financial right that supports merchant transmission expansion, therefore allowing lighter regulation of transmission, at least for some transmission expansions. We analyze the incentives provided by such a right under the particular assumptions of no lumpines, no economies of scale, and no market power.

Hogan discusses merchant-based transmission expansion in [24], while Joskow and Tirole present various problems with merchant expansion in [25]. We make no attempt to solve all the problems associated with merchant transmission that are described in [25].

Moreover, the main focus in the paper is on energy rather than on reserves or reactive power, and we omit discussion of market power in *both* the energy and transmission markets but appreciate that it can be a problematic issue, with important inter-relationships between energy, ancillary services, and transmission prices [14, Part 4]. Furthermore, our main result on incentives for transmission construction explicitly assumes the absence of market power and economies of scale. We believe that the results are nevertheless useful because they clarify that the "difficulty" with regulating (and deregulating) transmission is not due to the specifics of Kirchhoff's laws. Rather, the difficulties are due to issues that pose problems for any market, namely, lumpiness, economies of scale, and market power. These issues remain problematic for the restructuring of electricity markets.

III. Hedging of Transmission and Energy Prices

From a normative perspective, pricing of transmission services to customers should incent the efficient use of scarce transmission capacity. It is well known that locational marginal prices (LMPs) provide efficient incentives for generators and consumers and for transmission *utilization* [26]. In contrast, "contract path" pricing of transmission services usually provides an inefficient signal to users of transmission services [13].

Since LMPs and LMP differences are volatile, however, market participants typically desire financial instruments to hedge against the variation in LMPs and LMP differences. In the absence of transmission constraints and ignoring losses, CFDs can be used to hedge LMP volatility. However, when there are binding transmission constraints, CFDs alone cannot hedge a transaction from a generator to a consumer that are not co-located, since the LMPs at the generator and the consumer will differ and the difference will vary over time. As Bushnell and Stoft point out, exposure to volatility in LMP differences cannot be costlessly hedged by energy trading alone [9, Section 2.2].

Financial transmission rights (FTRs) [27] are in use in several electricity markets to hedge the volatility of LMP differences when there are transmission constraints. Such rights are either allocated to pre-existing transmission rights holders, or sold through a centralized auction or sequence of auctions, or both.

In all existing market implementations, the auctions for FTRs are conducted by the ISO, which sells the rights to bidders on the basis of their willingness-to-pay for the transmission rights. A purchaser of a "point-to-point" obligation FTR receives, over the contract duration of the FTR, the right to a revenue stream from, say, the day-ahead market, equal to the FTR contract quantity multiplied by the difference between the LMP at the point of withdrawal minus the LMP at the point of injection [27]. This revenue stream is paid from the congestion rental accruing to the ISO from offer-based security-constrained economic dispatch (OBSCED). Financial instruments other than point-to-point obligation rights present some difficulties because of the implications for the SFT but are being implemented in some markets [28, p. 49].

To ensure that the congestion rental is *adequate* to cover the payments to FTR holders, the allocated and auctioned rights must satisfy the SFT. That is, the allocated rights together with the auctioned rights must satisfy the transmission constraints, including contingency constraints, in order to ensure "revenue adequacy." (See [8], [13, Appendix], and [17] for formal statement and proof of this result.) The involvement of the ISO in the auction and the use of the SFT is predicated on the assumptions that:

1) the FTRs are paid out of the congestion rental accruing to the ISO in the OBSCED;
2) the ISO should remain on net, at least approximately, revenue neutral, with congestion rental from the OBSCED on average at least covering its obligation to FTR holders.

In later sections, we will change the first assumption and thereby create a transmission rights mechanism that is *exactly* revenue neutral for the ISO.

Transmission rights are often sold for durations that are much longer than a day, during which time some of the transmission lines represented in the SFT "test system" may actually be out of service. When lines are out of service, the revenue adequacy of the issued FTRs will not necessarily hold true. The ISO has several alternatives under these circumstances, such as:

1) it can assume some risk of revenue shortfall (presumably charging it as an "uplift" or averaging the shortfall from pricing intervals when there is an outage against other periods of positive net revenue);
2) the ISO can implement a derating policy or scale down the FTR payments;
3) the ISO can deliberately sell less rights than are implied by the SFT; or
4) the ISO can charge shortfalls to transmission owners.

The first alternative reduces the value of performing the simultaneous feasibility test, which is fundamentally to prevent revenue shortfall. The second alternative blunts the ability of the FTR to hedge transmission charges since transmission customers presumably want to hedge LMP differences whether or not there is a transmission outage, while the third alternative means that some transmission capability is not being offered to the market. That is, none of the first three alternatives is entirely satisfactory in the context of hedging LMP differences. The fourth alternative is used, for example, in New York for maintenance outages [28, pp. 52–53], [29, pp. 46–47].

TABLE I
COMPARISON OF CURRENT IMPLEMENTATIONS OF ENERGY AND AC TRANSMISSION MARKETS

Asset:	Underlying revenue stream:	Financial instrument:
Generation	Energy × LMP	CFD
Transmission	???	FTR

Furthermore, if a purchaser of point-to-point FTRs finds that its needs change, it will generally not be able to sell the right completely "over the counter" to another party, unless the other party requires an FTR between electrically very similar points. Consequently, relatively frequent auctions are required to enable reconfiguration of the transmission rights as transmission needs change.

To summarize, to ensure revenue adequacy, the ISO must only sell FTRs that collectively satisfy the simultaneous feasibility test, given an assumed test system. During periods when the actual capability falls short of that in the test system, the ISO must have some policy for either covering the revenue shortfalls or derating the system or must otherwise undersell the capability to minimize the likelihood of failing to be revenue adequate. Moreover, the ISO must repeat the auctions on a regular basis to enable reconfiguration of the rights.

These requirements for FTR auctions contrast greatly with financial hedging of energy bought and sold at a single bus. A CFD can be arranged between generators and consumers (or a load serving entity purchasing on behalf of consumers) or through an exchange that is not associated with the ISO. CFDs hedge the volatility of LMPs at a single location and enable financial bilateral contracts in the context of OBSCED. Generators and consumers have opposite tastes for exposure to LMP fluctuations: a high price is "good" for a generator and "bad" for a consumer and vice versa. Consequently, each can costlessly hedge price risk for a specific contractual quantity by signing a CFD.

The situation is illustrated in Table I, which compares current implementations of energy and transmission markets. As shown in Table I, for generation assets, the underlying revenue stream provides the basis for CFDs. However, there is no underlying revenue stream for transmission assets defined in current implementations of energy and AC transmission markets.

Because they are defined in terms of an underlying revenue stream, CFDs can be arranged without any intervention by the ISO and without the CFD posing any revenue risk to the ISO in the event of generation outages. CFDs can be arranged for short durations to support short-term opportunities or for long durations to support the financing of new investment. Moreover, because of their financial character, variations on the basic "obligation" CFD, such as options and collars, can be flexibly defined by contracting parties [30].

In practice, the convenient matching of generators and consumers is likely to benefit from a public exchange. For example, [17] describes a model of a sequence of auctions that can be used to arrange such financial contracts. However, there is no material need for the ISO to be involved in trading of CFDs.

The rest of this paper is aimed at the development of a property right definition for transmission and an associated financial mechanism that does allow for decentralized trading of transmission services, supports financing of new investment, and which is analogous to CFDs but applied to transmission. The property right that we propose makes transmission owners responsible for the financial implications of outages, as is the case for maintenance outages in New York [29, pp. 46–47], [28, pp. 52–53].

IV. Remunerating Transmission Investment

From a normative perspective, the remuneration of transmission investment should incent efficient transmission investment decisions that are consistent with maximizing welfare. That is, the property right conferred upon an investor in new transmission should produce a revenue stream that incents the efficient level of transmission investment. As Léautier points out in the context of a different mechanism for remunerating transmission investment, designing such a mechanism "is in many ways more technically challenging than the rate-setting of old" [31, Section 5.2].

In [2], Gribik *et al.* propose a *financial* right that depends on both the capacity and the electrical *admittance* of the line [32, Chapters 3 and 4]. The central insight of Gribik *et al.* is that, in contrast to a conventional transportation network, Kirchhoff's voltage law dictates that the contributions of lines to welfare depend not only on the their capacity but also on their admittance. This is because Kirchhoff's voltage law and the admittances determine the way in which flows are shared between lines, which in turn partly determines the contribution to welfare. Gribik *et al.* suggest a financial transmission right that involves payment based on the sensitivity of optimal welfare to both capacity and admittance.

The border flow right we define has a similar character to that proposed in Gribik *et al.* [1], [2] in that the underlying revenue stream for the border flow right is based on a similar sensitivity calculation. Gribik *et al.* define a financial right for transmission expansion that is based on the sensitivity of welfare and on the incremental change in capability from before to after installing the line. However, we use the sensitivity to define the underlying revenue stream of the border flow right, and then in Section VII, we will use this underlying revenue stream to define a financial right. The underlying property right in this paper is not based on an incremental calculation but is rather based on marginal cost principles, just as pricing energy at the LMP is based on marginal cost principles. The rights defined by Gribik *et al.* and in this paper are, however, equivalent in the limit of a marginal expansion and assuming that actual dispatch conditions match the "test system" used in the financial rights auction of Gribik *et al.*'s approach.

Because of its relationship to the sensitivity of optimal welfare, the border flow right provides incentives to build transmission that are analogous to the guidance provided by sensitivity-based transmission planning as described by Dechamps and Jamoulle [33] and Pereira and Pinto [34] and developed in the AC case by Cruz *et al.* [35]. In particular, since the underlying revenue stream for the border flow right is based on the sensitivity of optimal welfare, we will see that the border flow right incents efficient *marginal* transmission expansion by coalitions of beneficiaries when all expansion is "price-taking" in the sense of not affecting prices. This property holds for arbitrary networks. (See [20, Appendix, Theorem 5 and Corollary 6].)

Moreover, the border flow right confers payment on all lines and not just on the lines with binding capacity constraints. The payment mechanism therefore more directly encourages competitive suppliers of transmission. For example, consider a line with flow that is less than its capacity, but for which there is a positive difference in LMPs between its ends. Under the border flow right and the right proposed by Gribik *et al.*, such a line receives payment and can also increase its revenue stream by increasing its admittance and so attracting more power flow on it. By doing so, such a line will be allowing more power to be transferred from nodes with low prices to nodes with high prices and will therefore be increasing welfare. Such a line is also exposed to the cost of its losses and will therefore also have incentives to reduce losses.

In Section IV-A, we first consider the case of no contingency constraints and then in Section IV-B consider contingency constraints. In Section IV-C, we propose a property right for transmission.

A. No Contingency Constraints

If we first ignore contingency constraints, then the underlying revenue stream we propose for an owner of a transmission line joining nodes k and ℓ is given by

$$p_k P_{\ell k} + p_\ell P_{k\ell} \tag{1}$$

where

- the LMPs at buses k and ℓ are p_k and p_ℓ, respectively;
- the power flow from the line into bus k is $P_{\ell k}$;
- the power flow from the line into bus ℓ is $P_{k\ell}$.

This payment is equal to the congestion rental on a line in a system consisting of a single radial line between buses k and ℓ, where congestion rental is defined to be the difference between the demand payments and the payments to generators. However, as in [5, Equation (2)], we are proposing this payment for all lines, even in non-radial systems. As observed in Gribik *et al.* [2], (1) is a redistribution of the congestion rental to individual lines [5], [36, Section 3.5].

The equivalence between payment based on sensitivity of optimal welfare and payment based on (1) is proved in Theorem 2 in [20, Appendix], simplifying and generalizing the development in Gribik *et al.* [2]. The LMPs and the flows on the lines are determined by the ISO as the result of an OBSCED. The payment is made in each pricing interval based on the LMPs and the flows for that pricing interval. (For clarity, we have suppressed the explicit dependence of LMPs and flows on time.) Since $P_{k\ell}$ and $P_{\ell k}$ are generally of opposite sign and since positive flow from the line into the bus will usually be at the higher price bus, the revenue stream is usually positive. The case where the revenue stream is negative for a line is considered in the example in Section VI.

The revenue stream defined in (1) is analogous to the revenue stream paid to a generator for generation and paid by a consumer for its consumption. In particular, a generator is paid at the LMP for its generation, a consumer pays at the LMP for its consumption and, according to (1), a transmission line is paid at the LMP for energy that it delivers to the system and pays at the LMP for energy it receives from the system. Moreover, the ISO is *exactly* revenue neutral under this payment scheme under all dispatch conditions because power is conserved nodally. That is, all the power entering a bus also leaves that bus. Consequently, since all energy is bought and sold at the LMP, the net revenue to the ISO is exactly zero by definition. (See [20, Appendix, Theorems 1 and 3] for precise statements and proof.)

The proposed revenue stream to transmission owners is in contrast with the situation where only generation is paid at the LMP and only consumers pay at the LMP. In the latter case, the congestion rental accrues to the ISO. As discussed in Section III, the ISO must then pay out the congestion rental in order to make it approximately revenue neutral. This leads to complications if the implied operating point for the issued financial rights do not happen to correspond to a secure dispatch for the system.

B. Contingency Constraints

In the case where contingency constraints are binding, an exact calculation of the sensitivity of optimal welfare implies a payment involving the sum over base and contingency states of the product of net injection or withdrawal in a state times appropriate Lagrange multipliers [1, Appendix B]. This result is also proved as in [20, Appendix, Theorem 4]. In the simple case of a lossless system and only a single binding contingency constraint, the payment can be evaluated with (1) using the flows on the lines calculated for the contingency case and the LMPs. This payment scheme is also revenue neutral for the ISO.

C. Proposed Property Right

As a definition of a property right for transmission, we suggest replacing the question marks in Table I with (1). An approximation in the case of contingency constraints is to define the property right for transmission to be the right to receive the revenue stream specified by (1) based on the pre-contingency flows, even when contingency constraints are binding.

In the case of a lossless line, the revenue stream would equal the energy transported multiplied by the LMP difference. The approximate payment is easier to administer than payment based on the contingency flows and LMPs, since the pre-contingency flows are measured or estimated already in typical systems.

One property of the revenue stream that we describe is that an arbitrary collection of elements, including transmission lines, generators, and consumers, can be considered as one unit, paying the natural generalization of (1) that involves the flows at the borders between the unit and the rest of the system. This observation also motivates the name "border flow rights." The total payment to the unit is the same as the sum of the net payments to the individual elements considered separately so that the payment scheme is neutral regarding the aggregation of generation and transmission elements.

Furthermore, another property is that payments accrue to all transmission lines that contribute to welfare. Payments are not just associated to the binding elements as in the case of flowgate transmission property rights. There are also several other advantages compared to FTRs and flowgate rights, which are discussed in detail in [20, Section IV].

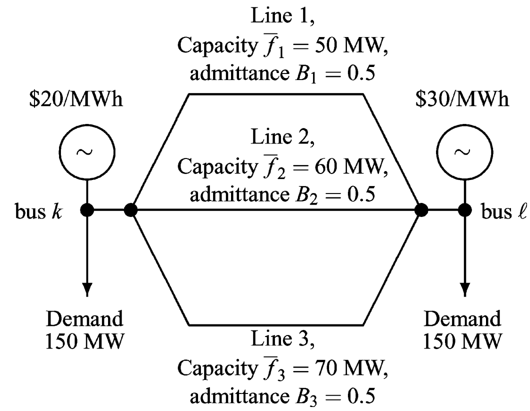

Fig. 1. Two-bus, three-line network with offers shown for typical hours on-peak.

High voltage direct current transmission also fits the model we describe since it is often modelled as a paired generator and demand. This payment is consistent with the revenue stream we propose.

V. Example Illustrating Revenue Stream

We consider a simple two-bus system, with buses k and ℓ, and a corridor of three lines joining the buses, lines $e = 1$, 2, and 3, each having the same admittance, with the absolute value of the imaginary part of the admittance equal to $B_e = 0.5$ units, $e = 1, 2, 3$. However, the lines have different capacities of $\overline{f}_1 = 50$ MW, $\overline{f}_2 = 60$ MW, and $\overline{f}_3 = 70$ MW, respectively. For simplicity, we assume that these capacities apply in both normal and emergency conditions and that, for each line, the capacity is the same for flow in each direction. (We ignore line resistance for convenience, but this can be included in the model.) The situation is illustrated in Fig. 1.

There is a generator at bus k that, during "typical" hours, offers its energy at $20/MWh and, during "exceptional" hours, offers at $60/MWh. For clarity in Fig. 1, we only illustrate the offer at bus k for typical hours. There is 150 MW of demand at bus k on-peak. There is also a generator at bus ℓ that offers its energy at $30/MWh during all hours. We ignore capacity constraints on the generators. There is 150 MW of demand at bus ℓ on-peak.

In Section V-A, we discuss the solution of OBSCED and the remuneration scheme for typical hours, while in Section V-B, we discuss the situation for exceptional hours. In Section V-C, we consider the incentives.

A. Typical Hours

In Section V-A1, we discuss the OBSCED problem for typical hours and its solution. Then in Sections V-A2 and V-A3, we discuss revenue streams for remuneration of transmission lines based on, respectively, (1) using contingency flows and LMPs, and (1) using the pre-contingency flows and LMPs.

1) OBSCED Problem and Solution: The OBSCED problem is to minimize the cost of the accepted offer quantities while meeting demand and satisfying the security constraints. [Since the demand is constant, the (revealed) welfare is a constant minus the costs.] The contingency constraints require that, in the event of an outage of any transmission element, the flow on the remaining lines are within ratings. Since there are three transmission elements, there are three contingencies and a total of six contingency constraints.

Let us write q_k and q_ℓ for the generations at buses k and ℓ, respectively. The system energy balance constraint requires that $q_k + q_\ell = 300$.

We write f_e for the base-case flow on line e in the direction from k to ℓ if all lines are in service. Because of the lossless assumption, the power flow from the line into bus k is $-f_e$, whereas the power flow from the line into bus ℓ is f_e.

The non-contingency inequality constraints require that

$$\forall e = 1, 2, 3, f_e \leq \overline{f}_e.$$

For this simple system, we can invert the power flow equality constraints and obtain the following expressions for the non-contingency inequality constraints:

$$\forall e = 1, 2, 3, \frac{B_e}{\sum_\tau B_\tau}(q_k - 150) \leq \overline{f}_e.$$

Let us also write f_e^ω for the flow on line e if there were a contingency on line ω, for $e, \omega = 1, 2, 3$. Again, $-f_e^\omega$ and f_e^ω are, respectively, the contingent flow from the line into bus k and the contingent flow from the line into bus ℓ, in the event of a contingency on line ω. Naturally, $f_\omega^\omega = 0, \omega = 1, 2, 3$.

The contingent flows are implicit functions of q_k and q_ℓ and must be limited so that

$$\forall e = 1, 2, 3, \forall \omega \neq e, f_e^\omega \leq \overline{f}_e.$$

As with the base-case constraints, we can invert the contingency-case power flow equality constraints and obtain the following expressions for the contingency inequality constraints:

$$\forall e = 1, 2, 3, \forall \omega \neq e, \forall \tau \neq e, \omega, \frac{B_e}{B_e + B_\tau}(q_k - 150) \leq \overline{f}_e.$$

For this OBSCED problem, the non-contingency inequality constraints are never binding, and so, we will not consider the non-contingency constraints explicitly. Moreover, because line 1 has the lowest capacity, the most binding contingency inequality constraints will always involve the flow on line $e = 1$ in the event of an outage of either line $\omega = 2$ or 3. We will not explicitly consider the four other contingency inequality constraints since they are never binding. Summarizing the effects of the constraints, the secure capability to transmit from bus k to bus ℓ is 100 MW.

Omitting the constraints that are never binding, the OBSCED problem for typical hours can be written as

$$\min_{q_k, q_\ell} \left\{ 30q_k + 20q_\ell | q_k + q_\ell = 300, \frac{B_1}{B_1 + B_2}(q_k - 150) \leq \overline{f}_1, \right. \left. \frac{B_1}{B_1 + B_3}(q_k - 150) \leq \overline{f}_1 \right\}.$$

The solution of this problem is $q_k^\star = 250$ and $q_\ell^\star = 50$, with $33\frac{1}{3}$ MW flowing on each line from k to ℓ pre-contingency and 50 MW flowing on each remaining line from k to ℓ in the event of any contingency.

The LMPs at k and ℓ are $p_k = 20$ \$/MWh and $p_\ell = 30$ \$/MWh, respectively. The two inequality constraints are identical, so that there is redundancy in the constraints: the sum of the Lagrange multipliers on these constraints is $\eta^\star = 20$ \$/MWh.

2) Payment Based on Contingency Flows: Using the payment scheme proposed in Section IV-B, the revenue stream to each line is equal to the flow on the line in the contingency case multiplied by the price difference between bus k and bus ℓ. That is, the payment is based on (1) where the flows are taken to be contingency flows. The payment is also equal to the sum of the sensitivities of optimal welfare to capacity and to admittance, respectively, multiplied by the capacity and the admittance [1, Appendix B], [20, Theorem 4, Appendix]. The sensitivities can be calculated from the solutions of the OBSCED problem [37], [38].

For line 1, the sensitivity of optimal welfare to capacity is $\eta^\star$. The sensitivity of optimal welfare to admittance is equal to $-(B_2/(B_1 + B_2)^2)\eta^\star(q_k^\star - 150)$. The revenue stream for line 1 is therefore

$$\eta^\star \overline{f}_1 - \frac{B_2}{(B_1 + B_2)^2}\eta^\star(q_k^\star - 150)B_1 = 500 \text{ \$/h}.$$

This is equal to the revenue stream based on the LMPs and the contingent flow on line 1 (on outage of line 3)

$$p_k\left(-f_1^3\right) + p_\ell f_1^3 = 500 \text{ \$/h}.$$

For lines 2 and 3, the payment depends on the "sharing" of the Lagrange multiplier $\eta^\star$ between the two binding constraints. At one extreme, suppose that the Lagrange multiplier on the constraint $(B_1/(B_1 + B_2))(q_k - 150) \leq \overline{f}_1$ is assumed to be equal to $\eta^\star$, while the Lagrange multiplier on the other constraint is assumed to be 0.

In this case, second-order sufficient conditions do not hold, and so, sensitivity results are not valid. Nevertheless, we can consider the results of formally applying sensitivity analysis and of using such analysis to define revenue streams. Applying sensitivity analysis, we find that the sensitivity of optimal welfare to the capacity of line 2 is zero and the sensitivity of optimal welfare to the admittance of line 2 is $(B_1/(B_1 + B_2)^2)\eta^\star(q_k^\star - 150)$. The revenue stream for line 2 would be

$$\frac{B_1}{(B_1 + B_2)^2}\eta^\star(q_k^\star - 150)B_2 = 500 \text{ \$/h}.$$

This is equal to the revenue stream based on the LMPs and the contingent flow on line 2 (on outage of line 3)

$$p_k\left(-f_2^3\right) + p_\ell f_2^3 = 500 \text{ \$/h}.$$

The sensitivity of optimal welfare to capacity of line 3 is zero and the sensitivity of optimal welfare to admittance of line 3 is zero, and so, the revenue stream is equal to zero. This is equal to the contingent flow on line 3 on outage of line 3, which is zero, times the marginal cost price difference.

At the other extreme, the Lagrange multiplier on the constraint $(B_1/(B_1 + B_2))(q_k - 150) \leq \overline{f}_1$ could be assumed equal to zero while the Lagrange multiplier on the other constraint would be equal to $\eta^\star$. In this case, the revenue stream to line 2 would be zero while the revenue stream to line 3 would be 500 \$/h.

If we "share" the Lagrange multiplier equally between the two constraints, then the revenue stream for both lines 2 and 3 would be 250 \$/h.

3) Payment Based on Pre-Contingency Flows: In this section, we consider the approximate payment based on (1) and using the pre-contingency flows. The flow on each line pre-contingency is $f_e = 33\frac{1}{3}$ MW, $e = 1, 2, 3$, so that the revenue stream to each line is

$$p_k(-f_e) + p_\ell f_e = 333\frac{1}{3}\ \$/\mathrm{h}, \quad e = 1, 2, 3.$$

This revenue stream differs from payment based on contingency flows but, as discussed in Section IV-C, would be easier to administer and may be a workable approximation to the exact sensitivity calculation.

B. Exceptional Hours

In Section V-B1, we discuss the solution of the OBSCED problem for exceptional hours. Then in Sections V-B2 and V-B3, we discuss revenue streams during these hours for remuneration of transmission lines based on, respectively, (1) using contingency flows, and (1) using the pre-contingency flows.

1) OBSCED Problem and Solution: In principle, we could re-solve the OBSCED problem with the changed offers from the generator at bus k during exceptional hours. The problem again has only two inequality constraints that can bind. In this case, the two constraints correspond to the limit on flow on line 1 in the direction from bus ℓ to bus k on contingency of, respectively, either line 2 or line 3.

However, because of the symmetry in the problem between typical and exceptional hours, we can write down the solution more directly based on the solution for the typical hours. In the following discussion, we will abuse notation somewhat by using the same symbols for both exceptional hours and typical hours. In exceptional hours, power will flow from bus ℓ to bus k and the solution of the problem is $q_k^\star = 50$ and $q_\ell^\star = 250$, with 33 1/3 MW flowing on each line from ℓ to k pre-contingency and 50 MW flowing on each remaining line from ℓ to k in the event of any contingency.

The LMPs at k and ℓ are $p_k = 60\ \$/\mathrm{MWh}$ and $p_\ell = 30\ \$/\mathrm{MWh}$, respectively, during exceptional hours. A key observation is that, in exceptional hours, the LMP difference between bus k and bus ℓ is three times in magnitude larger than in typical hours and of opposite sign. All the revenue streams can be calculated from this observation. The two inequality constraints are again identical, so that there is redundancy in the constraints: the sum of the Lagrange multipliers on these constraints is $\eta^\star = 60\ \$/\mathrm{MWh}$.

2) Payment Based on Contingency Flows: Using the payment scheme proposed in Section IV-B, the revenue stream for line 1 is equal to the flow on line 1 (on outage of line 3) multiplied by the price difference between bus ℓ and bus k

$$p_k\left(f_1^3\right) + p_\ell\left(-f_1^3\right) = 1500\ \$/\mathrm{h}$$

where f_1^3 is now the flow on line 1 on contingency of line 3 in the direction from bus ℓ to bus k. This is again equal to the payment based on the sum of the sensitivities to capacity and admittance, respectively, multiplied by capacity and admittance

$$\eta^\star \overline{f}_1 - \frac{B_2}{(B_1+B_2)^2}\eta^\star(q_\ell^\star - 150)B_1 = 1500\ \$/\mathrm{h}.$$

For lines 2 and 3, the payment again depends on the "sharing" of the Lagrange multiplier $\eta^\star$ between the two binding constraints. If we again "share" the Lagrange multiplier equally between the two constraints, then the revenue stream for both lines 2 and 3 would be 750 \$/h.

3) Payment Based on Pre-Contingency Flows: In this section, we consider the approximate payment based on (1) and using the pre-contingency flows. The flow on each line pre-contingency is $f_e = 33\ \frac{1}{3}$ MW, $e = 1, 2, 3$, so that the revenue stream to each line is

$$p_k(f_e) + p_\ell(-f_e) = 1000\ \$/\mathrm{h}, \quad e = 1, 2, 3$$

where f_e is now the pre-contingency flow on line e in the direction from bus ℓ to bus k.

C. Incentives

To analyze the incentives provided to a transmission owner by payment based on (1), consider the options open to an owner of an existing line to *change* the electrical properties of the line. Reconductoring and series capacitors can change the thermal capacity and the admittance, respectively. Moreover, there are various reconductoring options and various values of series capacitors that could be used to achieve a fine grained change in the thermal capacity or the admittance. Although such options for changing the electrical characteristics of a line are likely to have economies of scale, the total change in transmission capability may be a relatively small fraction of the existing capability in a corridor. Consequently, a marginal signal is likely to be useful in these cases. Furthermore, the marginal value of the line is positive for flows in both directions so that the revenue stream is positive both in typical and exceptional hours. In contrast, in an FTR-only system, the reversal of sign of LMP differences would require the FTR holder to refund to the ISO.

Under (1), whenever there is a binding transmission constraint, there are payments to and/or from all transmission owners, reflecting their marginal contribution to welfare. This contrasts with a flowgate transmission property right system, where payment would only be to owners of transmission associated with the binding constraints, but the payment would always be nonnegative. In the system illustrated in Fig. 1, there would never be any payment to lines 2 and 3 in a flowgate transmission property right system, despite their contribution to welfare: removal of either line 2 or 3 from service would lower welfare by increasing the amount of higher priced generation necessary to meet demand. The lack of remuneration for lines 2 and 3 means that there is no incentive for the owners of these lines to maintain their capacity in a flowgate transmission property right system and no incentives for lines 2 and 3 to increase flow by adding series capacitance. Further discussion of the drawbacks of flowgate right payment systems is in [2, Section I].

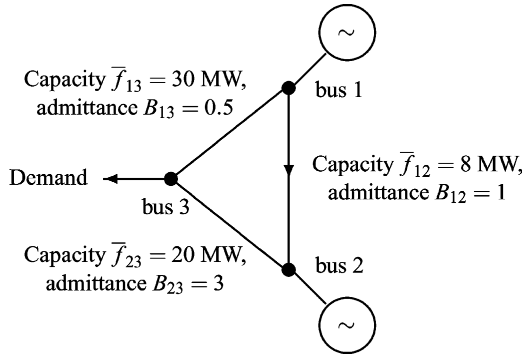

Fig. 2. Three-bus, three-line network from [6, Box 1].

Since, under (1), benefits accrue to all lines whose flows are affected, it would be necessary to form coalitions of beneficiaries to enable welfare maximizing funding of transmission expansion. This presents a free-rider problem and is more cumbersome than having all the benefits accrue to a single party as in FTRs and flowgate rights. However, transmission expansion currently typically involves the formation of coalitions of beneficiaries. Moreover, transmission upgrades often involve simultaneous upgrading of transmission elements in several locations, already necessitating the formation of coalitions [9, Section 2]. For example, series capacitors would have to be added to both lines 2 and 3 to increase the capability. As Bushnell and Stoft point out, an important role for regulators "is to oversee the coalition process and prevent barriers to investment along transmission paths" [9, Section 5.2]. Moreover, as Rosellón points out, "the regulator must then take measures to vertically separate the electricity industry, so that expansion projects may be undertaken by any economic agent" [36, Section 5].

It would be interesting to test empirically whether (1) based on the pre-contingency flows is a workable approximation to (1) based on the contingency flows when averaged over various operating conditions. We hypothesize that it might be. As mentioned in Section IV-C, it would be easier to administer a payment based on pre-contingency flows than one based on contingency flows. In the discussion in Sections VII and following, either the exact payment scheme based on contingency flows or the approximation based on pre-contingency flows could be used.

VI. Example Illustrating Counterflow

The example in Section V illustrates the properties of (1) in a contingency-constrained system with parallel path flow but in the absence of counterflow. To illustrate (1) in the context of counterflow, consider the three-bus, three-line example system from [6, Box 1] and shown in Fig. 2.

As presented in [6], there are generators at buses 1 and 2, with production q_1 and q_2, respectively, and there is perfectly elastic demand at bus 3 with marginal valuation of 33 \$/MWh. The marginal cost at node 1 is $q_1 \times 2$ \$/MWh/MW, and the marginal cost at node 2 is $q_2 \times 3.35$ \$/MWh/MW.

Unlike the system in Section V, there is no explicit consideration of contingency constraints for the system in Fig. 2, and so, we will only consider pre-contingency flows. Moreover, the system is lossless. The line between bus 1 and bus 2 has capacity $\overline{f}_{12} = 8$ MW and absolute value of the imaginary part of its admittance $B_{12} = 1$; the line between bus 1 and bus 3 has capacity $\overline{f}_{13} = 30$ MW and absolute value of the imaginary part of its admittance $B_{13} = 0.5$; and the line between bus 2 and bus 3 has capacity $\overline{f}_{23} = 20$ MW and absolute value of the imaginary part of its admittance $B_{23} = 3$.

In Section VI-A, we discuss the OBSCED solution with all lines in-service. Section VI-B discusses the incentives provided by this solution. Section VI-C considers the case where the ISO considers "commitment" and "de-commitment" of transmission in its dispatch problem, as discussed in [19]. The case where such actions are not possible is considered in Section VI-D, with a brief summary in Section VI-E

A. Solution With All Lines In-Service

The OBSCED solution, assuming all transmission lines are in-service, yields $q_1^\star = 15$ MW, $q_2^\star = 10$ MW, and LMPs of $p_1 = 30$ \$/MWh, $p_2 = 33.5$ \$/MWh, and $p_3 = 33$ \$/MWh [6, Box 1]. The welfare is 432.5 \$/h.

The flow on the line from bus 1 to bus 2 is at capacity $\overline{f}_{12} = 8$ MW. Under (1), its owner would be paid $p_1(-8) + p_2(8) = 28$ \$/h. The flow on the line from bus 1 to bus 3 is 7 MW. Under (1), its owner would be paid $p_1(-7) + p_3(7) = 21$ \$/h. Both of these payments are positive.

In contrast, the flow on the line from bus 2 to bus 3 is 18 MW, but the LMP at bus 2 is higher than the LMP at bus 3. The reason for this is that generation at bus 2 is needed to create *counterflow* on the line from bus 1 to bus 2. Under (1), the owner of the line from bus 2 to bus 3 would be "paid" $p_2(-18) + p_3(18) = -9$ \$/h. That is, the owner of the line from bus 2 to bus 3 must pay the ISO under (1).

B. Incentives

The payment to the owner of the line joining bus 2 to bus 3 receives a negative payment under (1). This is because the marginal contribution of the line to the welfare is *negative*. Consider the incentives provided by such a payment. In particular, if the line changes so as to lower the flow on the line somewhat, then the welfare of the system would improve. Such a change could be achieved by installing series reactance in the line.

For example, if the absolute value of the imaginary part of the line admittance decreased from $B_{23} = 3$ to $B'_{23} = 2$, then optimal transmission-constrained economic dispatch would involve $q'_1 = 16.4640$ MW, $q'_2 = 9.8561$ MW, and LMPs of $p'_1 = 32.928$ \$/MWh, $p_2 = 33.018$ \$/MWh, and $p_3 = 33$ \$/MWh. Welfare would increase from 432.5 \$/h to 434.78 \$/h.

The flow on the line from bus 1 to bus 2 is still at capacity $\overline{f}_{12} = 8$ MW. Under (1), its owner would be paid $p'_1(-8) + p'_2(8) = 0.72$ \$/h. The flow on the line from bus 1 to bus 3 is 8.464 MW. Under (1), its owner would be paid $p_1(-8.464) + p_3(8.464) = 0.61$ \$/h. Both of these payments are positive, although smaller than the payments in Section VI-A.

The flow on the line from bus 2 to bus 3 is 17.8561 MW, but the LMP at bus 2 is higher than the LMP at bus 3. Under (1), the owner of the line from bus 2 to bus 3 would be "paid" $p_2(-17.8561) + p_3(17.8561) = -0.32$ \$/h. That is, the line owner still must pay to the ISO under (1), but the payment by the line has reduced significantly due to the improved dispatch.

In other words, the marginal incentives provided by the payment encourages the owner of the line to change its line properties in a manner that improves dispatch and increases its revenue (or, in this case, decreases its payment to the ISO.)

Against this observation, as pointed out in [6, Section IV.A], if there is a large change in the line admittance, then the marginal incentives may not align with the incremental incentives. In particular, if the admittance is *increased* significantly from $B_{23} = 3$ to $B''_{23} = 12$, then the payment by the line owner would decrease to 5.56 \$/h. This change decreases welfare but also decreases the payment by the line owner.

C. Improved Dispatch of Transmission

The discussion in Section VI-A only considered dispatch of generation. As discussed in [19], the ISO could also consider dispatch of transmission in its operational decisions. In this case, because the marginal value of the line from bus 2 to bus 3 is negative, it would be natural for the ISO to consider removing the line from service for this demand and generation situation.

In many cases, it is reasonable to suppose that the marginal contribution to welfare would be consistent in sign with the incremental change in welfare between

- the line being out-of-service;
- the line being in-service.

Particularly in large systems with thousands of lines, the overall effect on dispatch of the presence or absence of a line would be well-approximated by marginal analysis. If this were true, then the line between bus 2 and bus 3 paid according to (1) could improve its financial position and improve welfare by being removed from the system, at least temporarily. The marginal incentives would align with the incremental incentives in such cases.

However, as discussed in [6, Section IV.A], for this particular system, removing the line between buses 2 and 3 decreases the welfare compared to the situation in Section VI-A. That is, the marginal contribution to the welfare of the line is of opposite sign to the incremental change in welfare.

The reason for this discrepancy between marginal and incremental incentives is that, in this system, when the line between bus 2 and 3 is out-of-service, the constraint on the line between bus 1 and 2 is still binding, but in the *opposite* direction. That is, when the line between bus 2 and 3 is out-of-service, the constraint on the line between bus 1 and 2 is binding in the direction from bus 2 to bus 1. The marginal contribution to welfare does not capture this effect and so is of opposite sign to the incremental contribution to welfare. To summarize, removing the line between bus 2 and 3 does not improve welfare in this case.

If the ISO can consider dispatch of transmission, there is nevertheless an improved dispatch for this system that obviates negative payments by transmission owners. In particular, if the line from bus 1 to bus 2 is removed from service, then optimal transmission-constrained economic dispatch yields $q_1^{\star\star} = 16.5\,\text{MW}$, $q_2^{\star\star} = 9.8507$ MW, and LMPs of $p_1^{\star\star} = 33$ \$/MWh, $p_2^{\star\star} = 33$ \$/MWh, and $p_3^{\star\star} = 33$ \$/MWh. The welfare increases from 432.5 \$/h to 434.8 \$/h. The flows on the in-service lines are below capacity, so payments to all lines are exactly zero for this dispatch condition.

This situation is analogous to the case where a lower voltage line is the limiting element in transfers and opening it can improve overall dispatch. If the ISO is able to identify such situations, it should presumably dispatch the transmission accordingly.

D. Incentives If All Lines Must Remain In-Service With Existing Characteristics

In [6, Section IV.A], it is observed that the lines in the system might all be required to remain in-service because of some (unspecified) reliability considerations. If this is the case, then the owner of the line between bus 2 and 3 will not voluntarily remain in-service and pay the ISO based on (1). A natural solution is a *make-whole* payment that, over a suitable horizon, ensures that in-service transmission always receives at least a zero net payment. This is analogous to make-whole payments for generation in unit commitment markets. Such payments are necessary whenever the marginal and the incremental contribution to welfare are of opposite sign, as is the case in this example. It is an empirical matter as to how often this would occur; however, the very tight constraints in this very small system (with flow on a constrained line reversing when the line from bus 2 to bus 3 is out-of-service) suggest that the circumstances in this system may not be very typical, so that such make-whole payments might be relatively rare.

E. Summary

This example illustrated the case of counterflow where power flows on a line from a higher to a lower priced bus. Under border flow rights, such a line would receive a negative payment, encouraging it at the margin to reduce the flow and improve the dispatch. Several related difficulties and remedies were discussed in this context.

VII. Contracts for Differences of Differences

The proposal (1) for remuneration of a transmission owner, whether based on pre-contingency or contingency flows, is independent of any financial contract definition. It depends only on line characteristics and the results of the OBSCED. In this section, we describe how the revenue stream can be used to fund a risk hedging financial instrument for transmission customers.

First consider a generator and a consumer at a bus ℓ. Suppose that the generator and consumer have signed a CFD to hedge the LMP at bus ℓ. The CFD provides a side payment from consumer to generator equal to a contract quantity q times the difference between a strike price for energy and the LMP at bus ℓ. The variation of LMP at ℓ is hedged for production by the generator equal to q and also hedged for consumer demand equal to q, since the sum of the LMP payments and the payment due to the CFD is always equal to q times the strike price. The CFD allows the generator and consumer, who have equal and opposite exposures to the variation of LMP at a bus, to both costlessly hedge their price risks for the quantity q [14].

Now suppose that the generator is located at a different bus, bus k. We now assume that the generator at k and the consumer at ℓ have signed a CFD to hedge the LMP at bus k for a contract quantity q. As is well known, a CFD based on the LMP at bus k is insufficient to hedge the price differences between buses k and ℓ [15, Section 2.2]. In a market with point-to-point FTRs, the consumer could hedge the price difference by purchasing an appropriate FTR of quantity q with point of injection k and point of withdrawal ℓ.

In contrast to an FTR-only system, we propose an alternative hedging instrument here, called a "contract for differences of differences" (CFDD). The CFDD is a contract between:

- the consumer (or generator or both); and
- the owner of the transmission line or lines joining bus k and ℓ.

The CFDD provides for a side payment to the transmission line owner equal to a contract quantity times the difference between:

- a strike price for transmission services; and
- the *difference* between the LMPs at bus k and ℓ.

The CFDD is so-called because it pays based on the *difference* between a strike price and LMP *differences* between two buses. Given a contract quantity of q, the CFDD would hedge the variation in LMP differences since the net payment for transmission services would always be q times the strike price.

A transmission owner and its transmission customer have equal and opposite exposures to the variation of LMP differences. As with the CFD, the CFDD allows them both to hedge their price risk for the quantity q. That is, in addition to defining an underlying revenue stream in Table I by (1), we would also suggest replacing FTRs by CFDDs in Table I. With these changes to the transmission property rights definition, there is a symmetry between energy and transmission markets: just as generators and demand have opposite exposures to risks of LMP variation that can be hedged with CFDs, transmission owners and customers have opposite exposure to risks of LMP *difference* variation that can be hedged with CFDDs.

As with CFDs, there is considerable flexibility to define variations on the basic "obligation" CFDDs that we have described. For example, there could be specific derating terms in the contract in the event of an outage. As another example, in the example system in Section V, "option" CFDDs could be written that provided payment based on the expression $\max\{0, p_\ell - p_k\}$ in typical hours and based on the expression $\max\{0, p_k - p_\ell\}$ in exceptional hours, without pre-specifying in advance the timing of the typical and exceptional hours.

As discussed in Section I, CFDDs are similar to "basis spreads" in current electricity markets [16]. However, in current electricity markets, unless they are funded from FTRs, such instruments must be synthesized speculatively from "long" and "short" energy positions. That is, they involve one party being paid to take on the risk of another. In the context of border flow rights, however, CFDDs enable both the transmission owner and the transmission customer to reduce their exposure to risk of LMP difference variation.

In the case of an FTR-only system, revenue adequacy for the ISO requires the FTRs to satisfy the SFT test. In contrast, with the proposed border flow right and the use of CFDDs, revenue adequacy associated with issuing financial transmission rights is devolved to transmission line owners. If transmission owners over-sell compared to their actual flows, then they are responsible for the shortfall. If they under-sell compared to their actual flows, then they will receive a volatile revenue stream.

Furthermore, during a transmission outage, the transmission owner will still be liable for the CFDD payment unless there are specific derating terms in the contract, providing a powerful incentive to the transmission line owner to make the line available and in-service whenever congestion in the network makes LMP differences large. The risk of ill-timed transmission outages is transferred from the ISO and transmission customers, who have little fundamental control of transmission outages, to the transmission owners themselves, who have more control and an ability to focus on long-term reliability issues. This is analogous to transmission owners funding shortfalls during maintenance outages as in New York. Given the risk to transmission owners, a workable system might, in practice, involve ownership of portfolios of transmission.

To summarize, since the CFDD is a purely financial contract, there is no need for any derating policy administered by the ISO. The transmission owner is financially responsible for its outages and must consider the implications in setting the strike price, contract quantity, and any derating terms in its contract with transmission customers. Moreover, unlike in FTR systems, risks to transmission customers under outage conditions would be explicitly set out in the contract rather than being implicit in a collection of ISO rules for derating FTRs.

The OBSCED can take place independently of financial positions of transmission owners and the purchasers of transmission rights. As in the case of CFDs, however, creditworthiness requirements may be appropriate for transmission owners that take on more risk than is covered by likely anticipated flows. Moreover, trading of CFDDs can also be facilitated by an exchange. To calculate the amount of CFDD payment that is covered by the revenue stream, a version of the simultaneous feasibility test can be conducted. (See discussion in [20, Section VII-C] for details.)

VIII. Trading of CFDDs

In this section, we sketch arrangements for trading of CFDDs. Further details can be found in [20, Section VII].

The CFDD mechanism allows for trading of financial transmission rights by entities other than the ISO because the simultaneous feasibility test to protect the revenue adequacy of the ISO is not part of the CFDD mechanism. In principle, the trading can even be completely decentralized.

Nevertheless, it may be helpful for transmission customers to be able to purchase contract paths of CFDDs that are assembled through a centralized exchange and for transmission owners to sell their CFDDs through such an exchange. As discussed in [20, Section VII.C], the exchange could implement a version of the SFT to ensure overall revenue adequacy for the traded contracts. There is no need for the ISO to be involved in the exchange. That is, the exchange can focus on the longer-term issues of transmission rights and creditworthiness, while the ISO remains focused on day-to-day operational issues. Moreover, such an exchange could trade CFDs and CFDDs *simultaneously*, providing long-term financial hedging instruments that would facilitate *both* generation and transmission capital formation. The exchange could also adjust the periodicity of offerings to adapt to market needs, without affecting the ISO.

IX. Merchant Construction

A. Discussion

Merchant generators hoping to build new construction can be expected to desire to sign long-term contracts (both CFDs and

CFDDs) to hedge themselves against LMP variation and to lock in prices in advance that their presence in the spot market may (temporarily) depress. Liquid forward long-term energy markets are an important part of encouraging merchant generation investment.

Similarly, merchant transmission providers can utilize forward markets to enable them to sign long-term contracts to hedge LMP variation and also lock in LMP differences. Because of lumpiness and economies of scale in transmission construction, it is conceivable that a transmission addition will significantly reduce LMP differences between the ends of the line at least during the first years of operation of a line until demand grows. The ability to sign contracts that are based on forward nodal energy price differences would allow such merchant transmission investment to be profitable despite temporarily depressing the LMP difference.

To date, only at-risk merchant high-voltage direct current (DC) transmission lines have appeared in any markets in the world. The controllability of DC transmission enables such lines to be represented in markets as simultaneous buyers and sellers of energy, therefore receiving a revenue stream as specified by (1). The introduction of border flow rights as a property right definition for *all* transmission would allow merchant AC transmission to also function as a simultaneous buyer and seller of energy, as implied by the revenue stream (1).

The combination of border flow rights and CFDDs would help to enable the financing of merchant AC transmission through forward financial contracts for energy, despite the lack of controllability of AC transmission. To summarize, CFDDs, built on border flow rights, allow forward financial energy and transmission markets to support the development of merchant AC and DC transmission.

The value of transmission in providing for flow in both directions is compensated directly under border flow rights. This feature of border flow rights avoids a drawback of current FTR formulations where deviation between the nomination of the FTR and the actual patterns of dispatch can reduce or negate the payment to the FTR holder. Moreover, there is considerable flexibility for a transmission provider to offer option CFDDs and other financial products that considerably generalize point-to-point obligation FTRs. To the extent that the LMP at one end or the other of a line is correlated with the LMP at a trading hub, the transmission owner could offer a CFDD written on that hub price.

As mentioned in the introduction, Bushnell and Stoft show that, under somewhat restrictive assumptions, any transmission investment that is detrimental to the grid will result in FTRs that have negative value to the builder [15]. Such a result does not extend to our proposed revenue stream as defined in (1). For example, consider the construction of a fourth line in parallel with the three lines shown in Fig. 1. If the line had the same admittance as the others but had a capacity of only 10 MW, then the welfare would be reduced by the presence of this line, even though it would be paid a positive amount under (1). Similarly to the discussion in Section VI-C, a natural solution to this issue is to provide the ISO with flexibility to "commit" or "de-commit" transmission lines in a way that is analogous to commitment of generation [19]. In particular, if the ISO has flexibility to disconnect a line if its presence reduces welfare, then the 10 MW line would be disconnected any time that the demand at bus ℓ exceeded 30 MW.

Another issue is that the benefit due to an expansion of the capacity of one line will accrue to the others. For example, consider expansion of the capacity of line 1 as in the example. For price-taking marginal expansions of line 1, the marginal benefit of added capacity of line 1 is shared amongst all three lines. Consequently, even in the absence of lumpiness, an efficient level of investment requires financing by coalitions of beneficiaries. (See [20, Appendix, Theorem 5 and Corollary 6] for precise statement.)

While coalition funding is somewhat cumbersome and presents free-rider and market power problems, transmission expansion currently involves such mechanisms in many jurisdictions. The border flow rights mechanism formalizes a property right for such expansion. To facilitate this process, there is a need for regulatory process that supports a third-party expansion process, as in Chile and Argentina [6, p. 30]. (See also [9, Section 5.2] and [36, Section 5].)

B. Example

Consider again the two-bus, three-line network shown in Fig. 1. We again focus on typical hours. Consider an expansion of the capacity of line 1 by 1.5 MW, with no change in admittance. This expansion increases the capability to import power from bus k to bus ℓ by 3 MW, increasing welfare by $(3 \text{ MW}) \times (\$30/\text{MWh} - \$20/\text{MWh})$, or \$30/h, due to the decrease in generation at bus ℓ and the increase in generation at bus k. This change does not affect the prices and so is a "price-taking" marginal expansion.

The flows on each line increase by 1 MW, and each line receives an additional payment of \$10/h. That is, the total increase in welfare of \$30/h due to the transmission expansion is paid out to the lines. Although perhaps somewhat cumbersome, a coalition of the owners of the three lines could finance the expansion of line 1 if the cost of expansion were compensated by the total increase in welfare of \$30/h.

X. Conclusion

In this paper, we have proposed a property right for transmission based on the approach of Gribik *et al.* [2], by defining an underlying revenue stream that accrues to the owner of a transmission line. Under the proposed border flow rights model, the owner of a transmission line is paid or pays at the locational marginal price for energy that it delivers to or receives from the rest of the system. Border flow rights using pre-contingency flows provide an approximation to efficient marginal incentives for transmission expansion by coalitions of beneficiaries. (See [20, Appendix, Theorem 5 and Corollary 6].)

Based on the property right for transmission, we have proposed a financial right for hedging LMP differences, called a contract for differences of differences, and provided examples of its use. The CFDD is based on the underlying revenue stream in the border flow right. Unlike previous FTR formulations, we first define a property right in terms of an underlying revenue stream that is independent of FTR nominations and then define a financial right that is built on the underlying property right.

Analogously to contracts for differences, contracts for differences of differences can be traded without an ISO. Nevertheless, exchange trading of CFDDs has several advantages over completely decentralized trading. Furthermore, both transmission and energy can be traded forward in one exchange, avoiding the bifurcation in current long-term markets. The ISO could be, but does not have to be, involved in the exchange.

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