POWER

PWP-030

Transmission and Generation Investment In a Competitive Electric Power Industry

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January 1996

This paper is part of the working papers series of the Program on Workable Energy Regulation (POWER). POWER is a program of the University of California Energy Institute, a multicampus research unit of the University of California, located on the Berkeley campus.

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for the California Energy Commission
Interagency Agreement 700-93-003
May, 1995

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January 5, 1996

Abstract

This paper concerns itself with the *long-run* efficiency of a restructured electric power industry; and therefore with incentives for capital investment both in generation and in transmission. To date, the debate over restructuring has focussed almost exclusively on problems of transition and of the functioning of the subsequent market in electric power, but has paid scant attention to the functioning of the market for capital investments.

We focus principally on what have been called "transmission congestion contracts" (TCCs). These were designed to be used in conjunction with "contracts for differences" to remove the congestion cost uncertainties from long-term bilateral contracts between generators and purchasers. We show that they fill this role well, and could thus provide the "bankability" needed by independent power producers when they seek funding.

In order to avoid the problems of regulating a transmission grid monopoly, it has been suggested that a party who invests in the grid should be rewarded with TCCs for the extra transmission capacity thereby created. This would reimburse the investor should his additions become congested and thus not available for his own use. We formalize the concepts put forward by William Hogan and others for rewarding investment, and then make a preliminary investigation into its incentive properties. We find that if power market participants, can form sufficiently cooperative coalitions, the incentive may be efficient. This analysis is intended to form the basis for a more definitive study of investment incentives.

*This work was partially funded by the California Energy Commission under Interagency Agreement 700-93-003. We are particularly grateful for discussions with William Hogan, and also acknowledge the assistance of Ed Kahn, Jon D. Edwards, Jim McCluskey, and Joseph Diamond, for their comments and input.

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Table of Contents

Executive Summary . . . . **iii**

Chapter 1
Introduction 1

Chapter 2
Bankability 3
2.1 Introduction: The Bankability Problem Defined 3
2.2 Using a CFD to Specify Bilateral Financial Performance 4
2.3 Transmission Property Rights and Congestion Contracts 7
2.4 How Transmission Congestion Contracts Augment the Bankability of CFDs . 9
2.5 Risk Reduction 11

Chapter 3
Defining Network Capacity 13
3.1 Introduction 13
3.2 From Injections to Power Flows 13
3.3 Capacity Limits and Feasible Dispatches 15
3.4 Understanding Nodal Spot Prices: Example 1 18
3.5 Computing Optimal Prices: Example 2 19
3.6 Summary 23

Chapter 4
Investment Incentive Properties of Transmission Congestion Contracts 24
4.1 Introduction 24
4.2 Allocating Rights to Reward Network Expansion 25
4.3 Some Detrimental Contractions are Encouraged 27
4.4 Some Detrimental Expansions are Encouraged 30
4.5 Beneficial Expansions are Encouraged 33
4.6 Disallowing Detrimental Network Changes is Not Simple 35

Executive Summary

Chapter 1: Introduction

Two features of a "contract network", spot prices and transmission congestion contracts (TCCs), have long-run ramifications for the viability of a competitive market in electric power generation. The temporal and locational volatility of spot prices discourages investment in generation unless risk-reducing financial instruments are available. Contracts for differences and TCCs will be examined in this regard. The rule for allocating TCCs to those who improve the network inevitable affects the incentives of those who will invest in the grid. The properties of these incentives will be examined.

Chapter 2: Bankability

2.1 A long-run contract with a fixed income stream provides "bankability" which helps to secure funding for non-utility generation investment. When power must be sold into a spot market, bankability becomes problematic.

2.2 A contract for differences (CFD) can be used to remove temporal spot-market fluctuations. Because it specifies only financial performance, it allows efficiency gains from trading with the spot market that are impeded by bilateral contracts for physical performance.

2.3 Three methods of specifying rights to network capacity are examined and the transmission congestion contract (TCC) is presented for further analysis. It pays the owner the price difference between two nodes times the directed power flow specified by the contract.

2.4 When coupled with CFDs, TCCs are shown to remove locational spot-market uncertainty, thereby enhancing bankability. Like CFDs, TCCs specify only financial performance and so allow the contracting parties to take full advantage of the spot market.

2.5 The question of whether TCC's are the most economical method of eliminating locational spot price risk is posed and suggested as a topic for further research.

Chapter 3: Defining Network Capacity

3.1 This chapter provides an introduction to optimal nodal spot pricing for the uninitiated reader who wishes to follow the details of the examples in chapter 4.

3.2 The first step in understanding spot prices is to find the flows on a network's links given a set of nodal injections. This is a pure engineering problem involving no optimization.

3.3 Some sets of injections produce line flows that would damage the network, or put it at an undue risk in case of contingencies. Such sets of injections are call infeasible dispatches. Computing the set of feasible dispatches is again an engineering problem.

3.4 The definition of optimal nodal spot price is introduced and used with simple laws of power flow to logically deduce the nodal spot prices in a simple example.

3.5 The discontinuities in the example's supply and demand functions are eliminated and it is resolved using optimization methods.

Chapter 4: Investment Incentive Properties of Transmission Congestion Contracts

4.1 TCCs are allocated to network expanders to increase the bankability of the related generation project, but the allocation rule inevitably affects the incentives of those expanding the network. This chapter investigates those incentives.

4.2 The allocation rule is: Let the expander claim any set of TCCs so long as the total set of allocated TCCs still corresponds to a feasible dispatch.

4.3 This rule encourages some detrimental contractions, although it will be worth while for the damaged parties to bribe those considering the detrimental expansion to hold off.

4.4 Some detrimental expansions are similarly encouraged.

4.5 The TCC allocation rule will encourage the affected coalition to make every beneficial expansion, provided they can cooperate in sharing the gains.

4.6 The problem of encouraged detrimental changes to the network could be elevated by the disallowance of such changes by the independent grid operator. However, the proper rule for determining which changes are detrimental is shown to be extremely complex.

Chapter 1
Introduction

Through a confluence of technological, and economic forces, the U.S. electric power industry today lies on the brink of fundamental change. New technologies have largely reduced economies of scale in generation and allowed for unprecedented levels of information transfer. These technological advances have combined with a series of regulatory initiatives to allow for increasing decentralization in the supply of electric power services [Kahn and Gilbert, 1993]. Pressure is now building to accelerate this process and to eliminate the traditional role of the monopolistic vertically integrated electric utility. California [CPUC, 1994] is at the forefront of these dramatic changes.

The elimination of the traditional utility requires the creation of a new paradigm. Several competing visions have emerged, [Blumstein and Bushnell, 1994] most of which share the common goal of a market where supply conditions, demand conditions, and transmission constraints, are reflected in price signals rather than accommodated through quantity constraints and planning processes. This is a vision with several early proponents (see Joskow and Schmalensee, [1983], Crew, [1987]). One highly detailed form of this vision is the near-real-time nodal spot market articulated by Schweppe, et. al. [1988].

Perhaps the most crucial segment of the power industry, one which will influence the evolution of competition in all other segments, is the transmission grid. By interconnecting many distribution systems and supply sources, the grid allows for the efficient use of resources and the reduction of risk. Through its unique physical properties and limitations, the transmission system also plays a key role in determining the location-specific cost of supply. Therefore any serious proposal for restructuring must provide workable methods for integrating the transmission system with the competitive forces driving the rest of the industry.

Previous analyses of electric transmission and competitive reform have concentrated almost exclusively on the role the grid will play in the formation and operation of an efficient market in generation. A first step is to better link the prices paid for transmission services to the costs of the facilities actually providing those services [Mistr and Munsey, 1992, Henderson,1994]. Ideally, pricing would reflect only the short-run marginal costs due to losses and congestion. This could be done through nodal spot prices or possibly through an as yet unarticulated pricing system for transmission services. The nodal pricing approach, developed by Schweppe, et. al., has now been elaborated by Hogan [1994a, 1994b, 1992] to include a definition of property "rights" to the transmission network. Specifically, these rights, called *transmission congestion contracts* (TCCs), give their owner the right to certain hypothetical congestion charges between a pair of nodes. They are designed to allow for the hedging of locational price risks and reduce a potential barrier to investment in generation. The limitation of these “rights” to financial payments is in keeping with the fact that almost all parties now concede that physical control of the transmission links must rest with a centralized grid operator.[1]

While TCCs address the problem of investment in generation, an issue crucial for the development of a competitive market, they also impact a second crucial issue, investment in the grid itself. This issue has not been widely addressed. The makeup of the network can have a significant influence on the underlying value of the assets connected to it. Defining the underlying costs and benefits of network expansions is extremely complex [Baldick and Kahn, 1993b]. If grid ownership is to be decentralized or otherwise subject to competitive forces, institutions must be developed to either give individual market participants the incentive to make efficient and beneficial grid investments or to regulate and oversee those participant's actions relating to the grid.

Unfortunately, the physical properties unique to electricity transmission create powerful externalities - both positive and negative - to grid enhancements. Thus an investment undertaken by any individual or coalition will have a physical and financial effect on many others. Although Garber, Hogan, and Ruff claim that "the combination of locational prices and tradeable (transmission) rights to compensation [now called TCCs] provides the right price signals to all involved" [Garber et. al., 1994]; this observation appears to be too optimistic.

In this report, we consider the long-run effects of two possible features of a competitive grid institution; nodal spot prices and transmission congestion contracts. Both of these features play a role in *bankability* of generation projects and in the *incentives* for grid expansion, which in turn both play crucial roles in the development of a competitive market for generation. The emphasis of this document is on William Hogan's "contract network" system of transmission property rights (TCCs).

In section 2, we define and analyze the property of bankability. We describe the roles of contracts for differences and TCCs in enhancing bankability. In section 3, we give a simplified explanation of network flows and of the determination of optimal nodal spot prices. We also discuss and define transmission rights. Section 4 discusses alternatives for allocating rights and documents for the first time, the TCC allocation method currently under consideration by Hogan. (This section is based on a discussion and three follow-up correspondences with William Hogan between November 1994 and February 1995.) We then examine the incentives for detrimental grid expansion and contraction produced by this allocation method, and prove a result concerning the incentive for beneficial expansions by coalitions of network participants.

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[1]This is in contrast to the debate over control of the dispatch of *generation*, in which there is still division between those who favor a central dispatcher and those who feel that decentralized contracts should determine dispatch levels.

Chapter 2
Bankability

Chapter Summary

This chapter analyzes the use of "contracts for differences" (CFDs) and "transmission congestion contracts" (TCCs) to make a bilateral contract "bankable"; that is to remove the uncertainty from its payment stream. This uncertainty arises from temporal fluctuations in the average market spot price, and from fluctuations in the difference between two spatially separated nodal spot prices. We first show that

- **CFDs eliminate the temporal average-spot-price uncertainty, except to the extent that either party wants to take advantage of the spot market. Such behavior cannot harm the other party.**

TCCs are then defined as paying their owner the difference between two spatially separated nodal stock prices times the quantity specified by the right, regardless of the level of actual power flow. We then show that

- **TCCs perform relative to spatial spot-price uncertainty exactly as CFDs perform relative to temporal uncertainty.**

2.1 Introduction: The Bankability Problem Defined

For a non-utility generator (NUG) to obtain financing for the construction of a power plant it is advantageous for that NUG to have a long-term contract for the sale of the plant's potential power generation. To the extent such a contract reduces uncertainty and makes it possible for a NUG to obtain financing we will say that the contract provides "bankability." In general bankability increases as the certainty of the income stream from the contract increases.

If either the NUG or its customer controls the connecting transmission line, then the long-term contract can provide a high degree of certainty because there is no question of access to the necessary transmission or of fluctuating spot or congestion prices. However since it is the purpose of restructuring to encourage and facilitate a robust and competitive electricity market, more distant trades must be anticipated. Often these trades will be carried out through a grid that is administered by an independent grid operator (IGO) over lines that are owned by neither of the contracting parties. Depending on the role of the IGO, this will result either in price uncertainty or quantity uncertainty. If the IGO conducts a spot market with market-clearing prices, then the price will limit the desired transactions to a feasible level. Thus any desired trade can be executed but at a price that cannot be guaranteed. If the IGO does not implement a market, then it will need to impose physical restrictions to insure the feasibility of the complete set of bilateral trades.

Thus bilateral contracts in a restructured industry will face a bankability problem no matter how the grid is administered. This paper will examine the bankability problem caused by uncertain prices in a system that maintains a spot market and in which all buyers and sellers are forced to trade with the IGO at spot-market prices. Two types of contracts have been proposed for dealing with this problem: *contracts for differences*, CFDs, and *transmission congestion contracts*, TCCs. We will examine the efficacy of each.

Two parties conducting a bilateral transaction within a spot-market system face two types of price uncertainty: temporal uncertainty and locational uncertainty. In spite of the fact that the two parties to a bilateral contract are forced to trade directly with the grid at fluctuating spot prices, they can completely insulate themselves from these fluctuations provided they face the same spot price. This is done through the use of a CFD. Such a contract goes a long way towards providing bankability so we will now examine it in some detail. Subsequently we will examine the use of TCCs for managing locational price uncertainty.

2.2 Using a CFD to Specify Bilateral Financial Performance

The Standard Bilateral Contract

Bilateral contracts take many forms, and in theory can include any provisions agreed to by the contracting parties. In order to have a simple standard of comparison for CFDs we will attempt to define a typical bilateral contract in a system where the parties can make direct physical trades, and will call this a *standard bilateral contract*, or SBC.

The two central characteristics of such a contract are a price and a quantity. Although quantity may be specified, it is recognized that if either party does not comply there will be no way to force compliance, since such action would necessarily be too late. Consequently financial penalties are generally specified along with the target quantity. For instance it is common to require the demander to pay for electricity that is not "taken", and to penalize the supplier for electricity that is not supplied. These penalties are said to enforce "physical performance" of the contract, or in legal terms, "specific" performance. For simplicity we will assume that the contract specifies a price, a penalty for reduced "take", and a penalty for reduced supply.

In the context of trade across a transmission grid run by an IGO, bilateral contracts still have these "physical and financial terms" (Stalon and Woychik, 1995, p.6), but the penalties for "imbalances" (the failures of physical performance just discussed) will probably be imposed by the IGO rather than by the contracting parties. This is because the "imbalances" directly effect the operation of the grid, causing the IGO to need to "rebalance the system," which is typically a costly procedure. According to Stalon and Woychik (1995, p.8) "PG&E suggests a bandwidth within which imbalances clear a the *transparent spot price*. For large imbalances, penalties are contemplated." As we discuss below the nature of these additional penalties will affect the efficiency of standard bilateral contracts.

In summary, a standard bilateral contract, specifies requirements for both financial performance, and physical performance, which in the legal language of actual contracts is termed specific performance. Contracts for differences are substitutes for SBCs that can be used in systems where all parties must trade with the IGO at spot market prices. As will be seen shortly these contracts cover only financial performance.

The Contract for Differences

We will now explain the workings and benefits of a contract for differences. In doing so we assume the existence of a spot market allowing traders to buy or sell any amount of power they want at any given location for a uniform spot price.[2] This price is, of course, determined by the desired trades and the desired levels of trade are determined by the spot price in a normal market-clearing process. Against this backdrop we compare a CFD with a standard bilateral contract (SBC).

The purpose of a CFD is to reduce or eliminate uncertainty of spot price variations over time. In describing CFDs below, we assume a uniform *locational* spot price for market participants. To address locational price uncertainty in a nodal spot market, other instruments are needed. One such instrument, the Transmission Congestion Contract, is described in the following section.

Imagine a supplier at node 1 and a demander at node 2 who wish to trade q units of power at a future time at which the unknown universal spot price will be p. The traders wish to trade at contract price p_C. This can be achieved indirectly by writing a "contract for differences," which we now define.

Definition: Under a **contract for differences (CFD)**, the demander will pay the seller $(p_C - p)\,q$, where p_C is the contract price, q is the contract quantity and p is the market's spot price.

Notice that if $(p_C - p)\,q$ is negative then the demander makes a negative payment which is, of course, carried out by the seller paying the demander. Notice also that there is no specification of quantities delivered or received because quantity transactions are carried out with the spot market.

Once such a contract is in place either party can assure himself of the trade that is specified by the analogous SBC, by simply trading the specified quantity.

- If the demander buys q, his net cost will be $pq + (p_C - p)\,q = p_C\,q$, independent of the supplier's actions.
- If the supplier sells q, his net income will be $pq + (p_C - p)\,q = p_C\,q$, independent of the demander's actions.

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[2] This discussion applies to a grid with no congestion where, in the absence of losses, all nodal spot prices on the grid will be identical.

As can be seen, a CFD is actually a bilateral contract for financial, but not physical, performance, though to avoid confusion we will not refer to it as a bilateral contract. The importance of specifying only financial performance can not be seen as long as both parties actually do perform physically in concert with the contract's nominal quantity, q. It is only when a traders fails to supply or demand the contract quantity that the potential benefit of the CFD becomes apparent. In the present context that would happen only when the spot price was below the supplier's cost of supply, C, or the spot price was above the demander's use value, V.

Consider the case in which the supplier fails to perform physically because the spot price is below his cost of supply, C. Under a SBC the supplier would like to subcontract his supply obligation at that spot price. However, if such an action reduces the original supplier's output below his acceptable "bandwidth", there could be a positive penalty that exceeds the spot price, for failing to fulfill the original contract. Under a CFD the supplier would ,as always, receive $(p_C - p)\, q$, which would typically be a reward when the spot price, p, is below C.[3] In fact, failure to supply will be deliberately chosen whenever the spot price, p, is very low, in order to capture this opportunity for profit. The benefit of the CFD consists of its ability to allow the supplier (or as we will see next, the demander) to capture the benefits of trading with the spot market, without in any way affecting the other party.

There is a symmetrical situation for the demander. Under a SBC, the demander will generally be subject to a "minimum take" provision, or some other penalty. Under a CFD, if the spot price is higher than use value, V, choosing not to accept delivery he will be rewarded by $(p - p_C)\, q$.[4] These relationships are summarized in Table 1, where it can be seen that traders who fail to fulfill a standard bilateral contract may have been better off operating under a CFD.

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[3]We have avoided discussing the more complex situation in which the spot price is below C, but is above p_C. This case only occurs when C is high due to plant specific factors, and p_C is low due to general market factors. In this case the CFD would penalize the supplier when he failed to generate, but there is every reason to believe the penalty would be less than under a SBC, because it would be the *minimum* penalty necessary to detour opportunistic behavior in a SBC environment.

[4]Again there is the possible complexity of V being lower than the spot price even though the spot price itself is low. In this case the CFD imposes a penalty of (p_C-p) which can never be as large as the penalty of a "take or pay" contract.

Table 1 Consequence of the Failure to Trade the Specified Quantity

		$p < C$	$p > V$
Supplier	CFD	**Reward** = $(p_C - p)$	Trade = q
	SBC	Possible Penalty	Trade = q
Demander	CFD	Trade = q	**Reward** = $(p - p_C)$
	SBC	Trade = q	Possible Penalty

Table 1 shows that since their trade of q is actually with the spot market, either party may decide to modify q. This does not effect the payment of $(p_C - p)q$ from buyer to seller. Generally if the spot price is very low, the generator will find it more profitable to stop generating, while if the spot price is very high, the demander will find it beneficial to stop demanding. This behavior is consistent with economic rationality and the parties capture the benefits of this rational behavior. This is in spite of the fact that they always have the contract's fixed price available to them. Under a standard bilateral contract, the participant's benefits from fluctuations in the spot price may be more limited. For this reason combining a CFD with the spot market produces a synthetic bilateral contract which can offer short-term advantages over standard bilateral contracts. The scale of these advantages will depend upon the degree to which performance penalties and transactions costs limit the ability of parties holding bilateral contracts to take advantage of favorable spot market prices.

When the network has only a single spot price, CFDs allow as much bankability as SBCs. But if spot prices are being used to handle congestion, and thus differ unpredictably between the supplier's node and the demander's, these contracts fail to provide the certainty of a standard bilateral contract with firm transmission access. Thus, in the presence of network congestion, there is still a bankability problem due to locational price uncertainty. The next two sections define transmission congestion contracts, and show how TCCs can be used to address that problem.

2.3 Transmission Property Rights and Congestion Contracts

Before analyzing TCCs and their effect on bankability, we need to define and describe the need for such an instrument. Since a TCC is essentially an indirect way of conferring a property right for transmission, we begin by reviewing three approaches to defining property rights to the transmission network. These approaches are: physical control of a link, link-based transmission rights, and transmission congestion contracts. Such property rights are defined in the context of a nodal spot market. The physical control of a link is obviously the strongest form of ownership, one which can affect usage on the entire system. The function of the latter two types of “rights” is to allocate the economic rents that should accrue to portions of the network.

Physical Control of Links

The most intuitive form of “ownership” of a transmission right is the control of its usage: to be able to transmit electricity along that link whenever one wants to. However, the process of network flows described in chapter 3 implies that exercising (or not exercising) control of a link can affect the ability of others to exercise the control of their links. In fact within the meshed part of a network, power transmitted between any two nodes actually flows on every link. The rigidity introduced by defining transmission property in this way will further limit the ability of dispatchers (whether a Poolco or decentralized suppliers) to adjust to fluctuating demand and supply conditions in an efficient manner. Almost all parties now concede that physical control of the transmission links must rest with a centralized grid operator.[5] This implies that transmission rights should be restricted to being financial in nature.

Link-Based Transmission Rights

One definition of a financial transmission right is to associate ownership with the right to collect rents accrued by that link in the network. This would imply, for example, that the owner of L_{ij}, the rights to a link connecting nodes *i* and *j*, would collect the price difference between those two nodes times the power flow on that line. This quantity would be $z_{ij}(p_i - p_j)$, where z_{ij} is the directed power flow from i to j.[6] One important but not immediately obvious characteristic of an LBR is that ***an LBR can have a negative value***. As Wu, et. al. have demonstrated, the existence of at least one link with a flow from a high to low price node is not an unusual outcome in a meshed network.

However the most telling criticism of this approach is the existence of major externalities both positive and negative that can result from a change in the network. The classic example of this is the construction of a line from *i* to *j* with low capacity and high admittance relative to an existing path from *i* to *j*. Such an “addition” to the network can easily reduce the total capacity from *i* to *j*. Thus rewarding an “expansion” with an LBR based simply on local physical properties, can encourage extremely harmful “improvements.”

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[5] This is in contrast to the debate over control of the dispatch of *generation*, in which there is still division between those who favor a central dispatcher and those who feel that decentralized contracts should determine dispatch levels.

[6] If the actual power flow was from *j* to *i*, then z_{ij} is negative.

Transmission Congestion Contracts

The transmission congestion contract (TCC) is the concept developed by William Hogan for distributing transmission "rights"[7] amongst a diversified ownership. Like LBRs, TCCs pay the right holder the price difference between the two nodes specified by that right. The two approaches differ in that ***the quantity which is multiplied by this price difference is defined by the right itself***, rather than by the actual flow on a specific link. We now define a TCC, which is a right to payments that are based on the operation of the network. ***These rights can be defined between any pair of nodes*** and are denoted by R_{ij}, where *i* is the transmitting node, *j* is the receiving node.[8]

Definition: The **transmission congestion contract (TCC)** provides the right R_{ij}, which pays the holder the amount $(p_j - p_i) \cdot R_{ij}$, which we will call the contract's **yield**.

Thus an individual TCC, R_{ij}, will pay the right holder $R_{ij}(p_j - p_i)$, no matter how much power flows between nodes *i* and *j*. One very important implication of this fact is that ***TCCs, unlike LBRs, need not be limited to existing physical links***. This allows TCCs to provide bankability to any bilateral transaction between two nodes anywhere on the network in a manner to be described in chapter 3. With TCCs, the question of directionality becomes an issue. Unlike Link Based Rights, where $L_{ij} = L_{ji}$, with Transmission Congestion contracts, $R_{ij} = -R_{ji}$. The key differences between the two approaches are summarized below. Like LBRs, TCCs can obviously also take on a negative value.

Table 2. Two Definitions of Transmission Rights

Name of Right	Symbol	Directional ?	Sign of Payment		Proportional to Power Flow ?
			$p_j > p_i$	$z_{ij}(p_j - p_i) > 0$	
TCC	R_{ij}	Yes	+	+ or −	No
LBR	L_{ij}	No	+ or −	+	Yes

In the next section we will see how the TCC concept allows congestion rents to be collected by market participants in a proportion exactly opposite to their long-term position on the generation market, thus providing a hedge against locational price fluctuations.

[7]Professor Hogan now prefers the phrase "Transmission Congestion *Contract*" (TCC) due to the confusion inspired by the word "right" in this context.

[8]This definition is good only for a lossless network.

2.4 How Transmission Congestion Contracts Augment the Bankability of CFDs

We now consider the ability of transmission congestion contracts to eliminate the remaining uncertainty from CFDs. According to Hogan, they were in fact designed for this purpose and we will find that they serve it very effectively. Their primary drawback will be displayed in chapter 4, where we consider their incentive properties for network expansion.

When spot prices differ between the buyer's node and the seller's node, there is a spectrum of possible contracts for differences. At one extreme the sellers spot price can be used, in which case the buyer pays the congestion charge, while at the other extreme, the buyer's spot price is used and the seller pays the congestion charge. In any case, the congestion charge, $(p_2 - p_1)\,q$, is an uncertain charge that must be borne by the traders. This section analyzes the potential of TCCs for reducing the uncertainty caused by congestion charges.

If trading partners own a TCC between their trading nodes (in the right direction), and if its power rating, R, is equal to the power they trade q, then they are perfectly insured. The shortfall between their contract for differences and the traditional bilateral contract will be $(p_2 - p_1)\,q$, while their collections from their TCC will be $(p_2 - p_1)\cdot R$, and R and q will be the same. In this case the combined CFD and TCC has the same bankability as the standard bilateral contract. This
is the basic insight into the functioning of TCCs, but we must next consider the possibilities for inequality between R and q.

Bankability with Shortfalls in Generation or Use

To analyze this more general case we will pick the symmetrical CFD in which the two parties split the payment of congestion costs. With this contract the buyer pays the seller $(p_C - \bar{p})\cdot q$, where $\bar{p}$ is the average of p_1 and p_2. Since the congestion cost is split, each trader will want to buy a TCC for power flow $q/2$ from node 1 to 2, the cost of which we will denote by C_R, and which will pay $(p_2 - p_1)\cdot q/2$.

Because the situation is symmetric we need only examine one trader, so we will pick the buyer and specify that the value to the buyer per unit of power purchased is V. First we will consider the general case where the buyer uses q_2, which may not equal q, the value specified in the contract. We compute the buyer's benefit, B, as follows:

B = Value of power − Cost of power − CFD payment + TCC collection − Cost of TCC.

$$B = V\cdot q_2 - p_2\cdot q_2 - (p_C - \bar{p})\cdot q + ½(p_2 - p_1)\cdot q - C_R$$

When $q_2 = q$, this simplifies to

$$B = V\cdot q - p_C\cdot q - C_R$$

This can be seen to be exactly the benefit from a standard bilateral contract at price p_C, and with an actual trade of q.

At the other extreme is the possibility that on the execution date the buyer will find the value of the contracted power to be less than the spot price at his node. This can happen either because p_2 is unexpectedly high or because V is unexpectedly low. In either case the power will not be purchased, or equivalently it will be purchased and then sold back to the grid. Thinking of it in the second way shows that the benefit, B, will be less by Vq, the foregone value, but greater by p_2q, the gain from sale. Subtracting Vq and adding p_2q to B when $q_2 = 0$ gives:

$$B = p_2 \cdot q - p_C \cdot q - C_R$$

Since by assumption, p_2 is greater than V, the benefit to the demander when $q_2 = 0$ is greater than the benefit under the standard bilateral contract, which was to be expected since the change was voluntary.

Once the buyer and seller have acquired the appropriate TCC, the contract for differences guarantees a benefit at least as great as from a standard bilateral contract.

Bankability When TCCs Do Not Track Contract Quantities

TCCs do in fact go a long way toward bankability, but they do not remove all uncertainty from the cost of transmission. In the stylized case just considered, where q continuously equals the magnitude of the right, R_{ij}, the cost of transmitting q will exactly equal the yield of the right. In its simplest conception, a TCC operates around the clock, 365 days per year at a precisely constant level, whereas power contracts are never filled with such precision and are generally not intended to be. Even though TCCs could be purchased to cover a particular time of day or season of the year, it will still be impossible to purchased one guaranteed to exactly match the future power flow from a dispatchable plant. Thus it will generally be impossible to buy a TCC that exactly matches the power flows covered by a long-run bilateral contract.

The best that can be done will be to purchase a TCC that covers all likely power flows and more. This will insure that all congestion costs are paid for by the yield of the TCC, but it will also produce an additional revenue stream during times when the right is not fully utilized in covering the power flows of the traders.[9] This additional revenue will of course be paid for at the time the right is purchased. ***Purchasing a TCC entails the exchange of a fixed sum for an uncertain revenue stream which will increase price risk***.

[9]Additional revenue is accrued whenever there is congestion along the path over which the TCC is specified. Although such congestion is less likely to occur when the owner of the right is not transmitting, there is no reason that it can not. Also remember that the TCC multiplies the nodal spot price difference by a constant that does not depend on the owner's use.

This situation is actually not as different from the current situation as it might at first appear. When a NUG signs a long-term contract with a utility, the purchased power will be shipped on lines that are probably owned by the utility, but may even be partly owned by the NUG. These lines must be sufficient, at all times of the day and year, to handle the peak power flow, even though they will be systematically underutilized at certain times and during certain seasons. During times of under utilization by the trading partners, they may sometimes produce extra revenue from external wheeling transactions or serve other purposes for the utility.

Thus in both cases more than enough transmission capacity will generally have to be purchased, and that extra capacity will produce some unpredictable additional income. Still there is a real difference between the two situations, which is most easily demonstrated by noting that unlike physical transmission assets, TCCs can produce negative income.

A TCC R_{ij} will accrue negative income if the contract turns out to cover a route for which the price at the supply node is higher than the price at the demand node, $p_i > p_j$. This can happen either because the acquired TCC is the right to transmit a flow opposite to the prevailing direction, or because power on this route is flowing from a high to a low price node. The first case is a highly desirable situation from a transmission standpoint, while the second case is one that Wu et. al. (1994) have shown to be a not unusual occurrence on a meshed network. In either case, if the trader's TCC more than covers their transmission needs during slack periods, they may suffer an unpredictable financial penalty for owning the unused part of their right.

2.5 Risk Reduction

The possibility of congestion, whether on the entire network or between any single pair of nodes, produces uncertain income streams. This imposes risks both on the payers of the congestion costs and on the collectors of congestion payments. In a nodal spot market there is a natural counter balance of risk between the market operator and individuals holding CFDs. Consider a transaction of q MWs between two nodes, supply node i and demand node j. The market operator collects $p_j\, q$ from the demander and pays $p\;\; q$ to the supplier, producing an income stream of $q\cdot(p_j - p_i)$. If the supplier at node i purchases a TCC of $R_{ij} = q$, the market operator will distribute $q\cdot(p_j - p_i)$ to the owner of that TCC. Supplier i's risk will have been reduced in the manner described above and the grid operator will have his price risk canceled. By selling the TCC to the supplier at i, both parties have eliminated their risk. This happens when a TCC exactly matches the physical trade of those who own it. In this case the uncertainty of congestion costs has been eliminated at no social cost.

TCCs are certainly not the only way to handle the risk of congestion charges. This risk could be reduced through forward spot contracts or by the purchase of insurance. In the case of insurance, the same type of cancellation described for TCCs would apply if the insurance agent owned the rights to collect the congestion charge for which he was writing insurance. Risk reduction could also be achieved in forward markets if the parties involved took opposite positions on that market.

In summary, the problem of how to mitigate the risk of congestion charges most economically, deserves considerably more attention, but the matching of collection rights with network usage appears to satisfactorily address the bankability problem.

Chapter 3
Defining Network Capacity

Chapter Summary

This chapter is a technical prelude to chapter 4 and is unnecessary for those familiar with the behavior of electrical networks and for those willing to take on faith all of chapter 4's statements about the behavior of example networks. It is aimed at the reader who wants a relatively painless introduction to techniques for analyzing simple linear networks and who wants a superficial exposure to some of the linear programming techniques typical of this field. In the process of explaining these techniques we solve an example network, which displays congestion on a weak line and a flow of power from a high nodal spot price to a low nodal spot price. Such a flow appears to be uneconomic yet it is a natural outcome of an optimal economic dispatch.

3.1 Introduction

In chapter 4 we will consider an allocation rule for TCCs that is based on changes to the set of feasible dispatches. The payoff to a network expander depends on this allocation rule and on changes in nodal spot prices. Because these interactions depend both on the set of feasible dispatches and on spot prices, the reader will need a basic working knowledge of how both of these are determined in an electric power network.

This section reviews the basic principles of power flow through a network, and the operation of the thermal and contingency constraints that determine the feasibility of dispatch. We then show how these constraints interact with nodal supply and demand functions to determine nodal spot prices, which include both the cost of energy and a congestion charge. All of this is done while developing an example that is later used to discuss the incentive effects of TCCs.

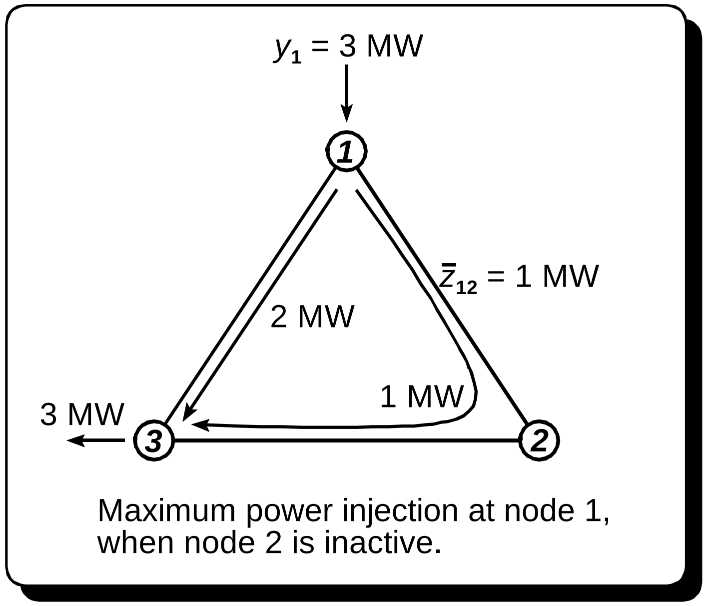
3.2 From Injections to Power Flows

We will first address the problem of determining the power flows along each line of a network when the power flows into and out of the network are known. Fortunately this problem is completely separable from the problem of constraints and nodal prices.

Our primary simplifications are (1), that network losses are negligible and (2), constraints relating to reactive power and voltage support are not represented. This leaves us with what is termed the “DC” flow model. We can thus represent the constraints of our dispatch problem with linear equations.

The example that we will be developing, shown in Figure 1, is a three-node network connected by three lines, with each line having the same admittance. The admittance of a transmission line is a physical property reflecting the ease of power flow in that line. Because the admittances are equal this example network has a particularly simple relationship between power injections, y_i , and power flows, z_l , on lines.

Figure 1. Power Flows with Equal Impedances



Consider a power injection at node 1 of 3 MWs. Because the admittances are equal, it is twice as difficult for the power to flow from 1 to 2 to 3 as it is to flow directly, so 2/3 of the power takes the direct path and 1/3 takes the longer path. This simple consequence of the physical laws of electricity is reflected in the flow equations (3).

$$
\begin{aligned}
z_{13} &= \tfrac{2}{3} y_1 + \tfrac{1}{3} y_2 \\
z_{23} &= \tfrac{1}{3} y_1 + \tfrac{2}{3} y_2 \\
z_{12} &= \tfrac{1}{3} y_1 - \tfrac{1}{3} y_2
\end{aligned}
\qquad \textbf{(4)}
$$

The subscript 13 on *z* indicates this variable measures the directed power flow from 1 to 3. Of course, these equations cover flows that are the results of an injection at node 2 as well as the injection at node 1 that we have depicted. These equations also assume that node 3 is the only demand node in the system. The fact that power flows can be represented by represented by linear equations, reflects the principle of superposition. This principle states that if one set, A, of injections causes a set (A') of power flows, and a set B of injections causes a set B' of power flows, then the sum of injections A and B will cause a set of power flows that is simply the sum of A' and B'. In other words if two sets of power flows are taking place simultaneously, on an unconstrained network, they do not interfere with each other. Notice the caveat concerning network constraints. We will shortly see how it complicates our problem.

Following the conventions and assumptions of Schweppe, et al. (1988) we can write the linear equations relating injections to flows for any linear network. Consider a network with N nodes indexed by $i \in [1,...,N]$ and M lines indexed by $l \in [1,..N] \times [1,..N]$[10]. Taking one arbitrary node as the *swing bus*, whose level of injection is determined by the net injections at the other nodes

[10]We will be indexing lines by the nodes which they connect (e.g. l = 1-3 for a line between nodes 1 and 3).

and conservation of energy, we can calculate the flows on all lines as a function of the injections at the other N-1 nodes. Using the admittances and connectivity of a network, a (N-1) x M *transfer admittance matrix*, H, can be calculated. In our example this is simply the matrix of coefficients multiplying the y's on the right side of equation 1. For the purposes of this paper, we will not show how to derive the transfer admittance matrix for a general network, but instead refer the reader to Appendix D, in Schweppe et. al. The element h_{li} of H represents the fraction of power injected at node *i* which flows on line *l*. The total flow on line l can therefore be expressed as

$$z_l = \sum_{i=1}^{N-1} h_{li}\, y_i \qquad \text{or} \qquad z = Hy. \tag{5}$$

The second statement of this equation uses matrix notation to express the same mathematics. From this equation we see that the line flows are simply a multilinear function of the injections.

3.3 Capacity Limits and Feasible Dispatches

Although equation 2 computes the power flows given any dispatch (set of injections), for some dispatches, the power flows will exceed the limits imposed on the lines. When this is the case the dispatch is said to be infeasible.[11] The restrictions imposed by line limits are simply expressed as

$$-\overline{z}_l \leq z_l \leq \overline{z}_l \;\; \forall \; l \tag{6}$$

When these constraints[12] are combined with equation 2 we have

$$-\overline{z} \leq Hy \leq \overline{z}. \tag{7}$$

[11]The constraints used in practice are contingency constraints, which are typically computed by assuming one line is missing and solving the dispatch problem as described here. That must be done for each possible missing line and the lowest resulting feasible flows are the contingency limits.

[12]The sign of z_l reflects the direction of flow on that line.

We now examine the effect of line capacity limits in our example. The origin of these constraints is of some interest and will be discussed shortly. We will first develop a graphical representation of the set of feasible dispatches for the present example.

Figure 2. Dispatch with Line 1-2 Constrained

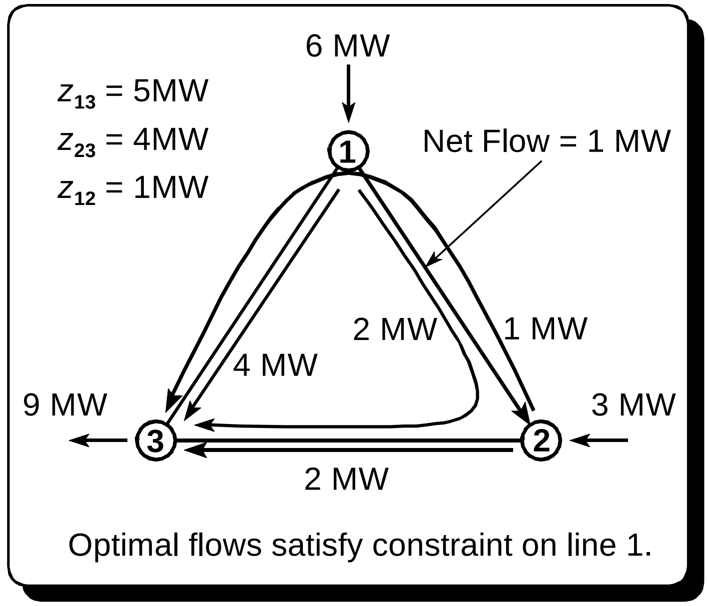


Figure 1 shows the primary capacity constraint of this example, which is the limit of 1MW on the flow in line1-2. As is shown in that figure, this restricts generator 1 to a maximum injection of 3MWs if it is the sole supplier, because 1/3 of the flow takes the path 1-2-3.

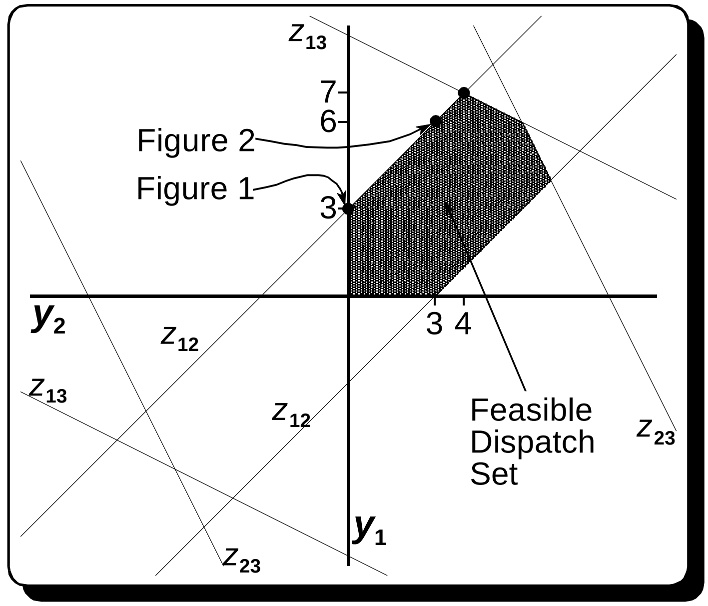
There is only one way for supply node 1 to inject more than 3 MWs, and that is for node 2 to begin supplying power. Because the network is symmetrical, a 3 MW power injection at node 2 will cause 1 MW to take the long path from 2 to 1 to 3. This flow will exactly cancel the 1 MW that was previously flowing from node 1 to 2. Once the flow on line 1-2 has been canceled, it is possible for node 1 to supply an additional 3 MWs. This process can continue until the limits of some other constraint are reached. So long as nodes 1 and 2 increase their supplies equally, the additional flows will always cancel on line 1-2. In figure 2 we show the result of nodes 1 and 2 both increasing supply by 3MWs from its value in figure 1. This will coincidently turn out to be the optimal dispatch once we have specified the supply and demand functions.

By examining these two cases where supplier 1 is constrained by line 1-2, we have begun to map out one of the six linear constraints that are imposed on the network's dispatch by the capacity limits of the three lines. (There is one constraint for each direction of flow on each line.) We now assign the other two lines capacity limits of 6MWs each. The feasible dispatches for this network can be therefore be described as those injection sets which produce flows that simultaneously satisfy all six inequality constraints. Because the set of injections is determined by any two of the injections, we can describe any dispatch with the pair (y_1,y_2). We can therefore graph the set of feasible dispatches in two dimensions. The six inequality constraints just mentioned, appear as three pairs of parallel lines in the two-dimensional graph. Since nodes one and two have generation only, the injections y_1 and y_2 are further constrained to be non-negative. This set is pictured as the shaded area in Figure 3 below.

The dispatches displayed in figures 1 and 2 lie on the top line labeled z_{12}. The set of feasible dispatches continues along this line until the capacity limit of line 1-3 is reached at 6MWs. At this point generator 1 is supplying 7MWs, 1/3 of which avoids line 1-3, and generator 2 is supplying 4MWs, 1/3 of which flows on line 1-3, for a total of 6MWs. Beyond this point, generator 2 must reduce output if generator 1 is to inject more power. Maximum power transfer to node 3 is achieved when both generators supply 6MWs and the flows on line 1-2 exactly cancel.

Graphing the feasible dispatch in this way demonstrates how it is natural to think of the capacity of the network in terms of the simultaneous nodal injections that satisfy both energy balancing and capacity limits. Unfortunately, the "transportation" of power involves a pair of injections, and, from a financial perspective, it is more convenient to think of transmission rights in terms of such an injection pair. However, such rights must be considered in the context of the entire network. For example, if someone owns the rights to 7 MW of capacity from node 2 to node 3, there can only be 4 MW of capacity available from node 1 to 3. The capacity available from 1 to 3 depends upon the net injections at 2. The simultaneous allocation of the rights to transfer 7 MW of rights to 2-3 and 4 MWs of rights to a 1-3 transfer represents a "maximal" allocation: neither can be increased without reducing the other. This is a concept we will discuss further in section 4.2.

Figure 3. The Feasible Dispatch Set



Thermal Limits and Contingency Constraints

We turn now to the origins of the line capacity constraints that we have been analyzing. The most basic of these is the thermal limit. This is different than the type of limit experienced by a roadway or gas pipeline; in those systems trying to push more supply through a path than is physically possible may cause the supply to seek other paths, but it does not destroy the congested link. Electric power does not respond to the fact that a link is near its capacity and seek another route; it just melts the wire. Thermal limits are affected by exogenous factors such as ambient temperature, but the modeling convention has been that a constant value for thermal limits can be used. This is sufficient for the purposes of our analysis.

Contingency constraints involve restricting the transmission network to operate at levels that can instantaneously withstand the loss of key elements. These restrictions usually require dispatching the network in a way that would appear sub-optimal when viewed as a static "snapshot" of the system. In the western U.S., such constraints are very significant and regularly constrain dispatch below the thermal limits of certain lines.

Walton [1993] describes the Western Systems Corporation Council's methodology for assigning commercial value to these constraints. Certain transmission "paths", such as Northern to

Southern California are identified and the maximum flow on any line traversing that path is constrained such that if any given line fails, the other lines serving that path will be able to handle the increased burden. Such an approach can be incorporated into the above representation of network capacity by modeling the flows of "contingent" systems, that is systems in which a key network element is missing. The resulting set of injections would have to then simultaneously meet the constraints of the actual system and the selected imaginary system [See Lee, et al., 1995]. A serious problem with this approach is deciding which are the "key" elements that the system must be able to do without. In a heavily meshed network, it becomes difficult to identify constrained paths and enumerating all possible paths would be extremely complex and could reduce the allowed dispatch to severely constrained levels.

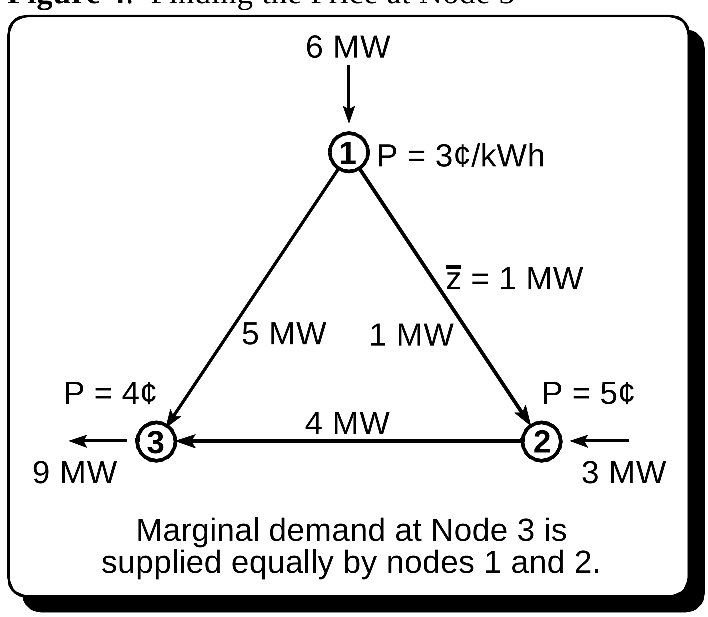
3.4 Understanding Nodal Spot Prices: Example 1

To demonstrate the concepts of nodal spot pricing, we continue with the 3 node example outlined above. This network belongs to the general class of networks (1 demand node, 2 supply nodes) which Wu, et. al. [1994] use to discuss problems they perceive with the contract network approach. In fact it mimics their example in having the same weak line, and the same flow from high price to low price.

We begin with a very simple specification of costs and demands. Let the costs at node 1 be 3¢ and the cost at node 2 be 5¢. We assume that the demand at node 3 is inelastic and equal to 9 MW. Ideally, all power would be supplied from node 1 and the spot price at all nodes would be 3¢. However, as we saw in Figure 1, at only 3 MW of power supplied by node 1, line 1-2 reaches its capacity limit of 1 MW.

In the second figure we see that injections at nodes 1 and 2 have both been increased by 3 MW, and that the constraint on line 1-2 is still satisfied. Note that the price at node 1 is less than the price at node 2, so this is the cheapest way to provide 9 MWs to node 3.

Figure 4. Finding the Price at Node 3



Now that we have determined the optimal dispatch by assuming only that supply at node 1 is cheaper than at node 2, we must face the problem of finding the actual nodal spot prices. To do this we need a definition. For economic efficiency we need prices to equal marginal cost; this is the standard requirement. The only complication in the case of an electric power network is in pinning down the source of supply. Because of the interactive nature of the network, even though it is possible to determine the source of the power supplied to any given node, this attribution will not correspond to the source of the next MW supplied.

Instead of approaching the problem in this manner it is necessary to consider the network as a whole, including all suppliers and all demanders, and then to define the net benefit of the system, NB. The net benefit is the sum of the benefits to all consumers, determined by integrating the area under their demand curves, minus the total cost of supply. We can now define the optimal spot price.

Definition: The **optimal spot price** at a node is the derivative of system net benefit (NB) with respect to power injection at that node.

Notice that when an additional KW is demanded it may be supplied either by a generator or by another demander who demands less as the price increases, or by any combination of suppliers and demanders. It can be shown that this definition is equivalent to another that is often easier to apply.

Fact: The **optimal spot price** at a node is the average of the prices at all other nodes weighted by their relative change in supply when power is injected at that node and optimally redispatched.

Note again that whether the marginal power is injected or removed does not matter, and that if there are other suppliers or demanders at the node in question, they must be considered as well.

To determine the spot price at node 3, first recall that when the cheap supplier at node 1 is supplying as much power as feasible, the binding constraint on node 1 requires that any increase in supply by node 1 must be balanced by an equal increase in supply by node 2. Since any increase in supply at node 3 comes equally from nodes 1 and 2, the supply price at node 3 is simply the average of these nodal prices, or 4¢. It is a simple calculation to verify that the cost of meeting 10 MW of demand at node 3 is 4¢ greater than the cost of meeting 9 MW of demand at node 3. The "marginal" change[13] in total system cost of increasing demand at node 3 is therefore 4¢.

3.5 Computing Optimal Prices: Example 2

When the specification of the network, power suppliers, and demanders is more complex than in the above examples, a generalized approach to computing spot prices is needed. To this end we draw again from Schweppe et. al. (1988) and their description of nodal spot markets. Note that the existence of a nodal spot market does not necessarily depend upon centralized control of the dispatch process by a pool operator. Any competitive market will form either explicit or

[13]Obviously, a change in 1 MW is not truly "marginal." The constant marginal costs and demand in this example allow us to make this extrapolation.

implicit spot prices that will differ by location. Schweppe provides a modeling framework and a theoretical ideal for the operation of such markets.

Symbol	Definition
N	The number of nodes
y_i	An injection at node i
$C_i(y_i)$	Cost of supply (benefit of consumption) at node i
z_l	A power flow on line l
$\bar{z}_l$	The maximum power flow on line l
H	Matrix to compute flow on lines from injections

This ideal begins with the presumption that there are clearly defined cost and benefit functions at the relevant nodes of the network. Let $C_i(y)$ define the cost of supplying y MW of power at node i. If $y < 0$, then $C_i(y)$ would be negative and represents the benefit of consuming $|y|$. In its simplest form, with no transmission losses and disregarding reactive power, the optimal dispatch problem is

$$\begin{aligned} &\text{Choose } y_i \text{ to minimize } \sum_i C_i(y_i)\,, \\ &\text{while keeping } \; Hy \le \bar{z} \quad \text{and} \quad \sum_i y_i = 0\,. \end{aligned} \tag{8}$$

If none of the transmission constraints were binding, the optimal solution would be characterized by the condition that the marginal cost at all supplying nodes equals the marginal benefit at all consuming nodes, or $C_i^{/}(y_i) = C_j^{/}(y_j) \;\forall\; i,j$. This value, representing the benefit of an increment of consumption or cost of an increment of production, is the *spot price* of electricity in the system. Since there is no congestion, the spot price is the same at all nodes.

To compute prices when one or more of the transmission constraints are binding, we form the Lagrangian of this optimization problem. Let p be the Lagrangian multiplier on the energy balance constraint and λ_l be the multiplier for the flow constraint on line l, then the Lagrangian form of the dispatch problem is minimize $\mathcal{L}$, where

$$\mathcal{L} = \sum_i C_i(y_i) - p\cdot\left(\sum_i y_i\right) - \sum_l \lambda_l\cdot\left(\sum_{i=1}^{N-1} h_{li}\,y_i - \bar{z}_l\right). \tag{9}$$

Differentiation of the Lagrangian with respect to a nodal injection y_i, yields

$$C_i^{/}(y_i) = p + \sum_{l=1}^{M} \lambda_l h_{li} \quad i = 1,..N-1$$
$$C_i^{/}(y_N) = p \qquad\qquad (\text{swing bus}). \tag{10}$$

The remaining Kuhn-Tucker necessary conditions for optimality are

$$\lambda_l \left(\sum_{i=1}^{N-1} h_l y_i - \bar{z}_l \right) = 0 \;\; \forall \; l$$
$$\lambda_l \le 0. \tag{11}$$

The line constraint multipliers, λ_l , are the shadow prices of the transmission lines. ***These shadow prices represent the marginal benefit to the system of increasing the thermal limits on a line***. The shadow price at a node (also the marginal cost/benefit at a node) is therefore equal to the unconstrained shadow price plus the shadow prices on congested lines times the fraction of an injection at that node (to be removed at the swing bus) which would flow on the respective congested line. It is important to note that the shadow price of a line's thermal limit is not equal to the difference in spot prices on the two nodes connected by that line. As can be seen from equation (5), ***the prices at various nodes will differ when there is line congestion***. These prices are known as the nodal spot prices. ***Nodal spot prices reflect the change in net costs to the system of an increment of supply at that node or conversely the marginal change in benefit from an increment of demand***. For the rest of this document, we will denote the spot price at node i as p_i.

Nodal spot markets have most frequently been described in the context of a centralized dispatcher/pool which would buy and sell all power at every node [SCE, 1994] [Garber, et. al., 1994]. In such an environment, the pool would collect what has been have termed "marketing surplus" [Wu, et. al.1994] or "Network Revenue" [Schweppe, et. al., 1988, Perez-Arriaga and Rubio, 1995] from its commercial operations. This surplus is defined as the price collected for power when injections are negative less that paid for power when injections are positive, or

$$\text{Marketing Surplus} = \sum_{i=1}^{N} p_i \, y_i$$

Note that in the example in Figure 4, this is 3, i.e. $9 \cdot 4 - 6 \cdot 3 - 5 \cdot 3 = 3$.

Example 2

When the cost and benefit functions at the nodes are more complicated, it becomes much more difficult to calculate prices in the above intuitive fashion. One needs to apply equation (10). Unfortunately equation (10) cannot be applied to the inelastic demand at node 3, so, for our second example, we will alter the network used in example 1 to include slightly more complicated cost and benefit functions. Both specifications demonstrate simple ways to construct network examples and both produce the same spot prices and dispatch levels.

Node	Example 1	Example 2
1	marginal supply cost = 3¢	marginal supply cost = $0.5y_1$¢
2	marginal supply cost = 5¢	marginal supply cost = $1.66y_2$¢
3	demand = 9 MW	marginal demand value = 0.5¢ (demand at p_3 = 8.5¢ is 0.)[14]

When computing the spot prices of the network under cost specification 2, it is necessary to determine which of the flow constraints are binding, i.e. which lines are at their thermal limits. From the optimality conditions (9), it can be seen that congested lines will generally have non-zero Lagrangian multipliers, λ_l, , while multipliers on uncongested lines are zero (there is zero cost reduction when the capacity of an uncongested line is increased). In this example, it is clear, as with specification 1, that line 1-2 will be operating at its thermal limit. The other lines will not be congested and their respective multipliers will be zero. Using equation (10) from above, we have

$$\begin{aligned} C_1^{/}(y_1) &= .5y_1 = p + \lambda_{1-2}h_{1-2,1} = p + \frac{1}{3}\lambda_{1-2} \\ C_2^{/}(y_2) &= 1.66y_2 = p + \lambda_{1-2}h_{1-2,2} = p - \frac{1}{3}\lambda_{1-2} \end{aligned} \tag{13}$$

and, for the swing bus, node 3

$$C_3^{/}(y_3) = p_3 = 8.5 + \frac{1}{2}y_3 = 8.5 - \frac{1}{2}(y_1 + y_2) = p \tag{14}$$

The line 1-2 is assumed to be at its limit, therefore we know that

$$\frac{1}{3}y_1 - \frac{1}{3}y_2 = 1 \tag{15}$$

Combining equations (13)-(15) yields

$$\begin{aligned} .5y_1 &= 8.5 - \frac{1}{2}(y_1 + y_2) + \frac{1}{3}\lambda \\ 1.66y2 &= 8.5 - \frac{1}{2}(y_1 + y_2) - \frac{1}{3}\lambda \\ y_1 - y_2 &= 3 \end{aligned}$$

[14]The demand function is $y_3 = -(17 - 2p_3)$, so the inverse demand function is $p_3 = 8.5 + 1/2y_3$ ($y_3 < 0$ for a removal from grid).

These 3 equations and 3 unknown variables are satisfied at

$$y_1 = 6,\ y_2 = 3,\ \lambda_{1\text{-}2} = -3$$
$$p_1 = 3,\ p_2 = 5,\ p_3 = 4$$

The Net Social Benefit of the system is simply $-\sum_i^N C_i(y_i)$, which in this case would equal consumer surplus (the integral of the demand function from $p_3 = 4$ to $p_3 = 8.5$) plus p_3y_3 less the cost of supply, $C_1(6) + C_2(3)$. This equals (4.5 x 9)/2 + 4 x 9 - .25 x 6^2 - 1.66/2 x 3^2 = 39.78. The value of $\lambda_{1\text{-}2}$ reflects the marginal value to the system of expanding the thermal capacity of line 1-2.

3.6 Summary

In this section, we have described the techniques used for analyzing the power flow and spot prices of a simple electric network. The formulas provided in section 3.2 are applicable to general networks, but a more thorough representation would require inclusion of other important network phenomenon, especially that of line losses. The procedures described in this section are nonetheless sufficient for understanding the general interaction of transmission line thermal limits, network capacity, and nodal spot prices. In section 4 we will use the insights of this section to analyze the problem that is more central to the focus of this document - the incentives for investment in a network.

Chapter 4

Investment Incentive Properties of Transmission Congestion Contracts

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Chapter Summary

This Chapter analyzes the incentive properties of TCCs and their rights with respect to investments in the transmission grid. Since these properties are largely determined by how such rights are allocated to the investors, we begin by establishing the allocation rule:

- **An investor may acquire any set of rights that does not make the entire set of publicly owned rights correspond to an infeasible dispatch.**

We then analyze the example of chapter 3 with regard to the possibility that the owner of a negatively valued TCC would eliminate the corresponding socially beneficial line. During this analysis the importance of side-payments become apparent as we find that:

- **In every case considered, either the owner of the TCC wants to keep the beneficial line, or some party would willingly bribe him to do so.**

The next section shows an example of a detrimental expansion that would be undertaken if side-payments were not allowed. Next we show that:

- **The coalition of all participants will have an incentive to make any beneficial investment.**

Such a coalition would again need to depend on side-payments in order to reach unanimous agreement. In summary we conclude that TCCs appear to induce economic investment with the qualification that sufficiently broad coalitions can form and carry out the appropriate set of side payments.

- **Whether such cooperative behavior is desirable and can be reasonably expected is left as a question for further research.**

4.1 Introduction

At the most fundamental level, there are three economic problems that must be solved by an efficient electricity industry: investment in generation capacity, investment in delivery capacity, and dispatch. Nodal pricing addresses the dispatch problem, while CFDs and TCCs address the generation problem, but the problem of investment in the delivery system has been largely ignored. This section is concerned with the transmission segment of the delivery system, the segment most crucial to restructuring the electricity industry.

Although transmission investment incentives have not been well studied, their importance has long been recognized. This recognition has lead to several bold assertions and a fair amount "folk wisdom". Notable among the more recent assertions are ones by Garber, et. al. [1994] that "with locational pool pricing, the benefits of a grid expansion accrue to specific grid users, providing incentives for these users to form a coalition to pay for cost effective expansions" and assertions by Oren, et. al.[1995] that "such pricing schemes will not provide the right incentives for transmission investments or expansions." This section attempts to clarify some of the controversy surrounding the investment incentives of TCCs.

4.2 Allocating Rights to Reward Network Expansion

A significant amount of the disagreement over the incentive properties of TCCs can be attributed to a lack of clarity about the allocation of those rights. (Since TCCs confer a right to collect a certain network congestion charge, we often refer to TCCs as rights.) To our knowledge, there has been no previous detailed analysis of how new or existing rights would be allocated amongst market participants. Wu et. al. [1994] have cited ambiguities in Hogan's statements on the subject, and their subsequent analysis of the investment problem [Oren, et. al. 95] does not consider any particular rule allocating rights to those who invest in the network.

The rule for allocating rights to network modifiers is of crucial importance because much of the incentive to expand or otherwise modify the network is determined by this allocation of rights, the other incentive being the consequent change in the modifier's nodal spot prices. The next two subsections pay particular attention to implications of the allocation rule for TCCs. The following one looks at the possibility of a more direct approach to controlling investment: a rule for disallowing detrimental network expansions.

Although TCCs were inspired by the need to enhance the bankability of long-term power contracts, they will inevitably play a role in governing network expansion. If that role is not a sufficiently positive one, they may have to be abandoned in spite of their usefulness as bankability enhancers.

Recall from section 2.3 that TCCs can be defined between any pair of nodes and do not refer to physical power flows, but are instead defined in terms of a directed contract quantity, R_{ij}. Specifically, the TCC defined by R_{ij} continuously pays it owner $R_{ij} \cdot (p_j - p_i)$.

Having defined the rights themselves, the only other administrative rule necessary for the determination of their impact on investment strategy is the rule for allocating TCCs to those who modify the network. Several possible rules present themselves. We consider the two most logical rules, maximal rights and feasible rights, below. The feasible rights approach has some key advantages and also appears to be the one preferred by Hogan.[15] Consequently, the remainder of this chapter analyzes the investment incentives presented by this approach.

[15]This rule evolved over the course of a conversation and several private correspondences with Prof. Hogan, and we do not believe it has been previously made completely explicit

Assigning Maximal Transmission Rights

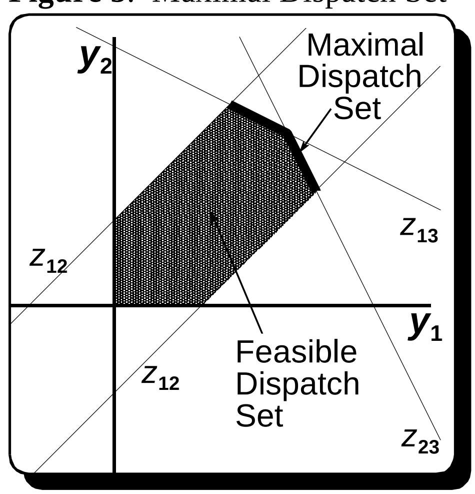
A natural path to follow when attempting to define an allocation rule, is to insist that each time the network is expanded, the expander will be given, and forced to accept, one of the maximal available set of rights. This avoids the myopia of link based approaches, since it takes the entire network into account whenever any part of it is modified.

Implementation of this procedure obviously necessitates defining the concept of a maximum set of rights. Any network expansion would presumably increase this set and the subsequent increase in rights would be awarded to the expander. If the "expansion" were detrimental, and caused a decrease in the maximal set of rights that could be supported by the network, then the "expander" would be rewarded with rights that were opposite to some existing rights. Presumably, these would have negative value and correctly penalize the culprit. Note that these opposite rights would in no way change the value of the existing rights to the holders of those rights.

Because TCCs are purely financial in nature, providing only the right to certain monetary collections, any number of TCCs, can be allocated and honored over a given network. Because there is no necessary limit on the total allocation of TCCs there is flexibility in defining the maximal set of rights. Although TCCs do not confer any physical rights, pretending that they do provides a fairly natural criterion for a network's maximal allocation of rights.

There are several ways to define a maximal dispatch, but the one that seems most natural is the most strict. It requires that no increase in the magnitude of any injection be possible without a corresponding decrease in the magnitude of some other injection. This is pictured at the right. This definition of a maximal dispatch can then be used to define a TCC allocation rule by relying on the correspondence between sets of TCCs and dispatches that we have just described. That allocation rule is formalized as follows.

Figure 5. Maximal Dispatch Set



<u>**"Maximal" Allocation Rule**</u>**:**
The reward for an expansion of the network is any set of rights, $\{dR_{ij}\}$, of the expanding agent's choosing, provided $\{R\} + \{dR_{ij}\}$ is maximal, and where $\{R\}$ is the set of previously allocated rights.

Our investigations indicate that while this approach is certainly more complex than the following "feasible rights" approach, it has no advantages over it.

Feasible Rights

A second approach to this problem, and the approach we will focus on in the remainder of this paper, is to allow a network expander to adopt any set of TCCs he wishes, so long as the resulting set of allocated rights is feasible.[16] To define feasibility we again imagine that all rights are to be physically and simultaneously dispatched. We require that the flows caused by such a dispatch not violate any system constraints. If none are violated, the set of rights is considered feasible. Thus the "feasible" approach to awarding rights insures that at all times the existing set of TCCs corresponds to a feasible dispatch.

According to a result proved by Hogan [1992a] and confirmed by Wu et. al. [1994], any feasible set of rights has a convenient financial property. The result states that as long as the set of allocated TCCs represents a feasible dispatch, the revenue collected by rights holders will not exceed the network's marketing surplus produced by an optimal dispatch. It would therefore appear that feasibility provides a fairly appealing constraint on the total set of allocated rights. However, Perez-Arriaga and Rubio [1995] have shown that the marketing surplus alone will likely not recover full network cost. Furthermore, as Wu et. al. pointed out, ***while the optimal dispatch produces a non-negative profit for the network, a sub-optimal dispatch may produce an even greater profit***. Most parties, including Hogan, believe that the incentives given to a Poolco/Opco dispatcher will have to be somewhat divorced from the marketing surplus created by the dispatch. When the profit made by Poolco is divorced from the marketing surplus, and is instead secured by some other mechanism, the need to maintain a positive cash flow from marketing surplus is diluted.

The observation that the marketing surplus does not impose a necessary constraint on the set of TCCs led Oren, Spiller, Wu, and Varaiya [1995] to conclude that "the feasibility condition in Hogan's (1992) formulation is unnecessary and meaningless." This conclusion is based upon the evidence available at the time that "the feasibility condition is only intended to serve as a solvency condition for the market maker." However, feasibility plays a second important role, that of defining the allowable allocations to grid investors. Accepting this notion leads to the following rule for rewarding network expansions.

<u>"Feasible" Allocation Rule</u>:
The reward for an expansion of the network is any set of rights, $\{dR_{ij}\}$, of the expanding agent's choosing, provided $\{R\} + \{dR_{ij}\}$ is feasible, and where $\{R\}$ is the set of previously allocated rights.

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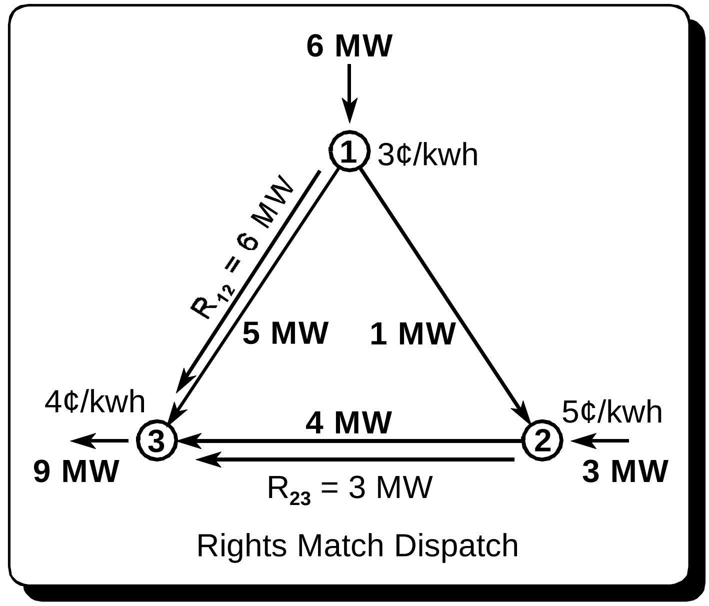
[16]The "existing set of rights" and "resulting set of rights" are exactly the set of rights that the marketing agent (IGO) is obligated to support financially, in the first case, before the expansion, and in the second case, after the expansion.

4.3 Some Detrimental Contractions are Encouraged

We now consider some implications of the feasibility allocation rule when it is applied to the example of section 3. In so doing, we extend the work of Oren, et. al. [1995], who utilize a similar example to demonstrate "perverse incentives" to "eliminate link 2-3." They did not consider the re-allocation of property rights that would be implied by an adjustment to the network configuration. The "perverse incentives" may therefore, in some cases, be overstated.

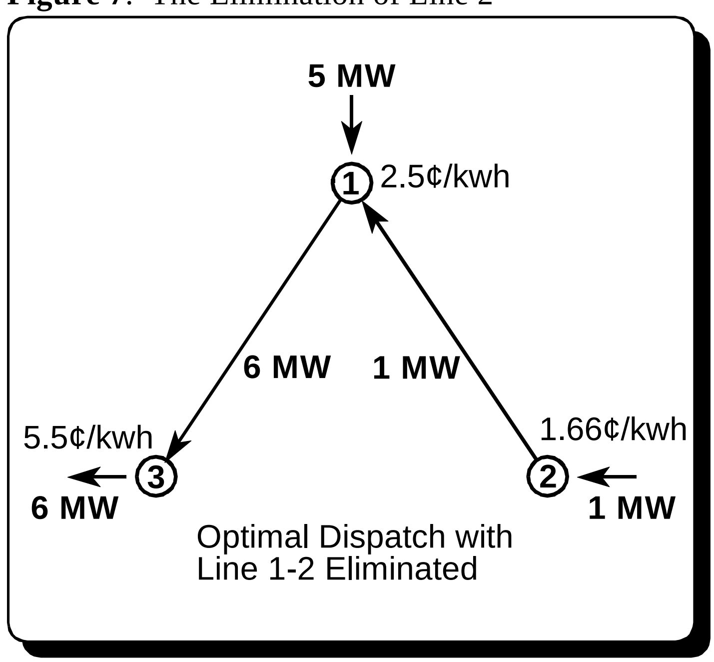
Figure 6. TCCs that Match the Dispatch



For this example, we will consider a set of allocated rights which match the optimal dispatch. There are several qualitatively different sets of maximally feasible rights, and infinitely many scaled down versions of these, but it is natural to examine the set which matches the dispatch since these rights give the expander maximum possible benefit. As we will argue later, choosing rights to match the dispatch also maximizes the benefit to the expander.

Notice that although the TCCs match the dispatch, they do not correspond explicitly to the line flows. Generator 1 ships 6 MWs to node 3, and has a right to 6 MWs of congestion charge between nodes 1 and 3. There is also a right corresponding to generator 2's shipment of 3 MWs to node 3, but we will not yet assign the ownership of that right.

Figure 7. The Elimination of Line 2



We wish to analyze the effect of these TCCs and of the rule for TCC allocation on the incentives for different parties to eliminate link 2-3. To do this we must know the optimal dispatch after that link is eliminated.

We solve for this dispatch by recalling that the capacity of link 1-3 is only 6 MW, which will cause that line to be congested, and the consumption at node 3 to be exactly 6 MW. The demand function at node 3 then determines the price. $p_3 = 8.5 - 6\cdot(\frac{1}{2}) = 5.5$¢. This demand will be suppled by both generators up to the point where generator 2 is limited by the 1 MW capacity of line 2-1, if that happens before their combined output reaches 6 MW. First we check the spot price at node 2 at a supply of 1 MW and find it to be 1.66¢. Then find the price at node 1 with a supply of 5 MWs. This is $p_1 = 5\cdot \frac{1}{2} = 2.5$¢. At these dispatch levels, node 2 is cheaper and will supply as much power as is allowed by transmission constraints. The net benefit of this dispatch (see section 3.5) is $(3 \times 6)/2 + 5.5 \times 6 - .25 \times 5^2 - 1.66/2 \times 1^2 = 34.92$. Before the line was eliminated, net benefit was 39.78. Eliminating line 2-3 therefore reduces the net benefit of the system. We now consider the possible elimination of line 2-3 under several different TCC ownership scenarios.

Ownership by a Transmission Line Company:

We begin with the possibility that line 2 was built by a "third" party, in other words not by any generator or demander on this grid, and that this third party owns the TCC on the line. In this case the owner of R_{23} is losing \$30/hr ((5-4)¢ times R_{23}) on her "right". Clearly she would like to return this right to the IGO, but she is restricted by the feasibility condition. She would be allowed to return the right (if necessary on the pretext of having made some nominal grid modification) if the outstanding set of rights after his return was feasible. But the single right to transmit 6 MW from 1 to 3 is not feasible, because the thermal limit on link 1-2 would be exceeded if it were dispatched. Her only recourse seems to be to eliminate line 2, which makes R_{13} feasible, allowing her to retire right R_{23} and eliminate her losses.

There are two qualifications that should be made to the results of the above example. TCCs are based on the assumption that they will be owned by participants, or coalitions of participants, in the power market. This is not the case in the present example, where the TCC owner has no position in the generation market. Given that lines would probably be built with (short term) excess capacity, however, it is not implausible that some allocated rights would not be linked to a CFD but would rather be held in anticipation of future contracts. A second qualification to the example is the possibility that another party may be interested in the fate of line 2 and may try to prevent it's elimination. In fact generator 2 will be seriously harmed by its elimination, and consequently would be willing to accept right R_{23} from the third party without compensation, if the only alternative was its elimination. Thus there is no reason for the third party to impair line 2-3, since she can simply give R_{23} to generator 2.

Ownership by a Generator at Node 2:

We have asserted that generator 2 (G2) would accept right R_{23}, but this deserves to be checked, which we do now as part of an analysis of G2's ownership of right R_{23}. This state of ownership is the one most frequently cited by the proponents of TCCs. As we have stated, TCCs were designed to enhance the bankability of long-term generation contracts. The right will serve this purpose if it is owned by G2. The benefit to G2 from the existence of link 2-3 is the difference between his profit of $p_2 y_2 /2$ = \$75/hr with the line and his profit of $1\cdot 1.66/2$ = \$6.6/hr without the line. The gain from line 2 is \$68/hr which far outweighs the cost of R_{23} which is \$30/hr. The open question of the generality of this result is an interesting one.

Incentives of a New Entrant:

As a further check on the incentives of TCCs, we consider the possibility that a fourth party, not owning R_{23} or having any other interest in the system, might eliminate line 2-3. A self contained system of grid-investment incentives should ideally cover this possibility, since line elimination can be socially beneficial. If a fourth party did eliminate line 2-3, it would, by the rights allocation rule, be required to accept a set of rights that restored the complete set of allocated rights to feasibility. Since R_{23} is the problematic part of the allocated rights set, feasibility can be restored if the fourth party is assigned the reverse right, R_{32} = 3MWs. After the elimination of line 2-3, this right has a value of $(p_2-p_3)\cdot R_{32}$ = (1.66¢ − 5.5¢)·3000kW/hr = −$120. Elimination of line 2-3 by a "new" party is therefore unprofitable, as it should be.

Ownership by a Generator at Node 1:

Our last case, and one that is more likely than it will at first appear, assumes that R_{23} is owned by G1. This could arise if line 1-3 is built after lines 1-2 and 2-3. If no rights for 2-3 have been previously allocated, G1 must accept 3 MW of R_{12} if he wants 6 MW of R_{23}, in order to make the latter allocation feasible.

Line 2-3 has some value to G1 because without it he will only be able to sell 5MW at 2.5¢ (see figure 7) instead of 6MWs at 3¢; this makes its value (6000·3¢/2 − 5000·2.5¢/2) = $27.5/hr. But this is less than the cost of R_{23} which we know is $30/hr. G1 would therefore eliminate line 2-3 if he had no other options. But as we have seen before, G2 may be willing to take it off his hands, a far more profitable alternative for G1. Thus neither of the generators would prefer to eliminate line 2-3.

The fact that a network may contain lines on which power is flowing from a high price to a low price node has led to the observation that, in a disaggregated market, some parties may find it profitable to eliminate such a line, even if it harms the network as a whole. The purpose of this section was to illustrate two important qualifications to this line of reasoning, having to do with property right allocation and side payments between participants. Under the feasible rights allocation rule, the party which eliminates that line may have to accept rights which offset ones which were destroyed. This may or may not reduce or eliminate incentives for eliminating the line. Furthermore, the fact that total net benefit has decreased indicates that some parties would be better off making side payments to preserve the line, or accepting a negatively valued TCC, rather than see it destroyed. Whether such actions are politically acceptable, equitable, or could even sustain a stable environment where threats to eliminate lines are not repeatedly made are topics for further research.

4.4 Some Detrimental Expansions are Encouraged

Most often grid modification means grid expansion, so in this section and the next we will focus on the way in which TCCs encourage and discourage expansion. It would be most desirable for TCCs to possess the following two properties.

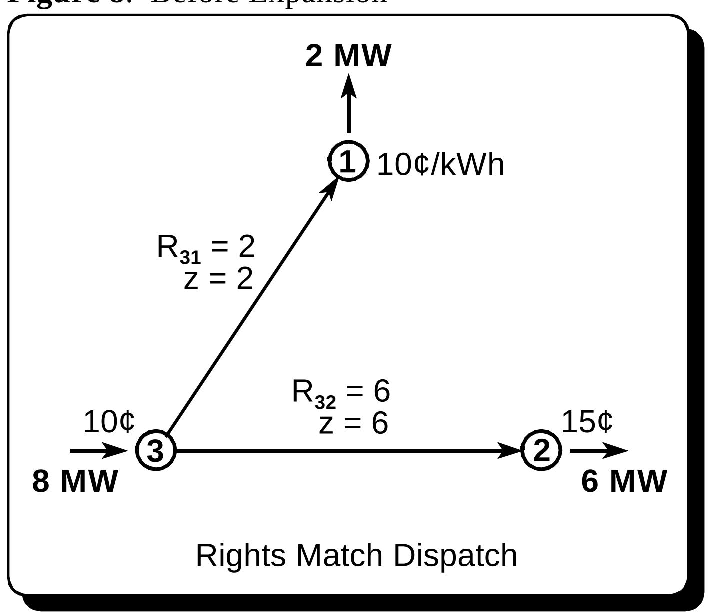
(1) All socially beneficial expansions are encouraged.
(2) All socially detrimental expansions are discouraged.

We now investigate these properties with respect to the rule for rewarding network expansion.

In this section we give an example of a network expansion that is detrimental to network participants as a whole, but which would be beneficial to one of the players. Like many network "expansions" this one makes possible some dispatches that were previously infeasible, but eliminates the feasibility of others that were previously feasible. We will term this a *mixed* expansion, while an expansion that does not eliminate any previously feasible dispatches will be termed a *pure* expansion. This concept is discussed further in the next section.

This example of an encouraged detrimental expansion will lead us to assert that the governing body of the network must forbid some types of expansions. One obvious possibility would be to forbid all mixed expansions. We will argue that this rule is too restrictive, eliminating many socially beneficial expansions. Since mixed expansions need to be allowed, the fact that this example is based on a mixed expansion does not detract from its interest.

Figure 8. Before Expansion



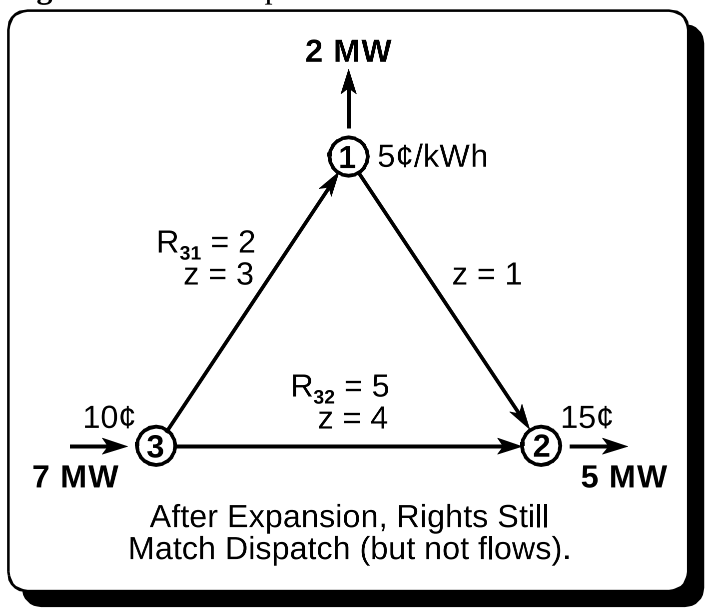
Our example begins with the three-node, two-line network shown in figure 8. This is the same network used in previous examples except that line 1-2 does not exist. Unlike previous examples, node 3 is now a supply node and nodes 1 and 2 are demand nodes. Node 3 can generate power for 10¢/kWh in the range of supply under consideration. Nodes 1 and 2 have fixed demands of 2 and 20, respectively. Node 2 also has the ability to self generate for approximately 15¢/kWh. As a consequence of these facts the nodal spot prices are those shown in figure 7.

Capacity rights equal to the dispatch are owned on both lines by the supplier. In the case of the capacity right from 3 to 2, the supplier earns 30¢, but on the right from 3 to 1 she earns nothing.

Consider a network expansion that consists of adding a line of capacity 1 from node 1 to node 2. This produces the network and dispatch shown in figure 8. The network configuration is now identical to the ones used in chapter 3 and in earlier sections of this chapter.

Power therefore flows according to the flow equations (4) of chapter 3, and the binding constraint is again the new, small capacity line 1-2. Since demand at node 1 is 2, the flow equation $1/3y_1 - 1/3y_2 \leq 1$ requires that y_2 be no less than -5, which means node 2 can demand no more than 7MW from the network.

Figure 9. After Expansion



The spot price at node 2 is therefore the self-generation cost of 15¢/kWh. An increase of demand at node 1, however, will allow a corresponding increase of supply from node 3 to node 2. This is due to the flow constraint on line 1-2, and the fact that using power at node 1 tends to relieve this constraint. Since every kWh of energy used at node 1 costs 10¢ to generate, but saves 5¢ in generation costs at node 2, its net social cost is only 5¢/kWh, so this is the spot price at node 1.

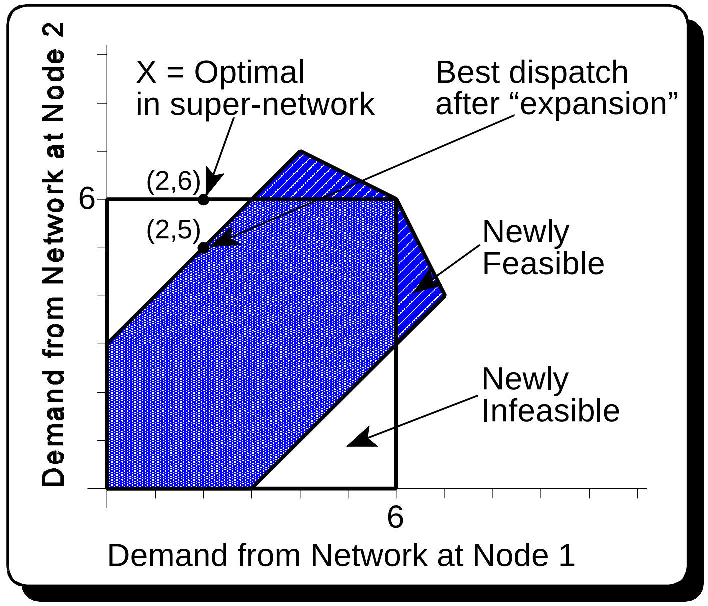
Clearly demander 1 has much to gain from this expansion as he saves 5¢/kW·2MW on his cost of power. Demander 2 loses nothing since his spot price is unchanged. The supplier suffers a 10¢ loss $R_{31}(p_1-p_3)$ on her capacity right from 3 to 1, which now has a negative value. The problem with this expansion is that it reduces the social surplus, as is easily seen by the fact that node 2 must now self-generate 1 more MW at a cost of 15¢ in place of the 10¢ power which it previously bought from 1. Demander 1 still buys the same 2 units from supplier 1.

So far we have not discussed the allocation of rights required by the expansion. The new rights, which we will term the *incremental* rights, when added to the original rights, must result in a feasible dispatch after expansion. The pre-expansion allocation of rights is no longer feasible, since the set of injections represented by the existing rights violates the flow constraint of the new line. One possible set of rights is clearly the set of rights that matches the new dispatch, since this dispatch is by definition feasible. This implies a particular set of incremental rights. We will now show that this particular set of incremental rights has the following desirable property:

- **Matching Incremental Rights are Optimal**
  The set of incremental rights that causes the total set of allocated rights to exactly match the actual system dispatch, is at least as valuable as any set of rights available to a network expander. These rights are termed *matching incremental rights*.

This property follows from the Hogan's result on revenue adequacy, which was discussed in section 4.2. By definition, a set of rights that exactly matches the dispatch will reward its owners with payments that exactly equal the marketing surplus, by the revenue adequacy result, no other set of rights can do better for rights owners as whole. If the expander chooses a different set of incremental rights, this has no impact on either the dispatch or on the rights of others, thus it will not affect their revenue. Consequently, choosing a different set of incremental rights can either have no effect or, if the choice reduces the total revenue collected from rights, it will reduce the revenue of the expander.

Figure 10. A "Mixed" Expansion



This motivates the choice of rights represented in figure 10. These rights imply that the expander has taken the matching incremental rights, which are $\Delta R_{31} = 1$, $\Delta R_{12} = 1$, $\Delta R_{32} = -2$. This set of rights is discoverd by looking at the changes of flows on intividual lines, but it is not a unique expression of the incremental matching rights. A fully equivalent way to express this package of rights is as follows: $\Delta R_{31} = 0$, $\Delta R_{12} = 0$, $\Delta R_{32} = -1$. Note that the difference between these two sets is a set of three rights from 1 to 2, from 2 to 3, and from 3 to 1, all of value 1, that map out a uniform circular flow. Such a flow corresponds to the null dispatch since there are equal flows on the network into and out of each node. (Such a flow cannot be induced by any dispatch.) This observation about our particular example corresponds to a general principle.

- **Equivalent Sets of Rights Differ by the Null Dispatch**
  Two sets of rights are equivalent, meaning they will generate the same income under any set of nodal prices, if and only if the difference between them is a set of rights that corresponds to the null dispatch.

Since $p_2 - p_3 = 5¢$, the value of $R_{32} = -1$ will be $-5¢$, as will be the value of the matching incremental rights accepted by the network expander. Therefore, neither supplier 3, demander 2, nor an outside party would find it profitable to invest in this expansion. The demander at node 1, however, would still be better off undertaking the expansion as the 10¢ he saves on his cost of power will outweigh the 5¢ he loses on the new right. Left to his own devices, then, demander 1 would undertake a transmission expansion that is detrimental to the system as a whole. Once again, other parties who are hurt by the expansion could pay demander 1 not to add the detrimental line. Once again, there are equilibrium and fairness issues involved in such a transaction that would need to be addressed.

If fairness is a concern or if forming coalitions of grid participants to bribe those would make detrimental contractions cannot be done efficiently, this example shows that a network using feasible rights allocations should not simply allow its members to conduct any expansion that is profitable to themselves. It appears that some degree of oversight will be needed. There must be rules for deciding which expansions are allowable, and which are not. This question is briefly examined in the final section of this chapter.

4.5 Beneficial Expansions are Encouraged

Network expansions can affect network participants either by changing the price of electricity at their node, or by changing the value of a TCC they own. Because of this, an expansion can effect many participants. Consequently, it can be necessary to include many participants in a typical expansion decision in order to insure that the decision will be correct. Because it is difficult to define the smallest necessary set of participants, and because including an unaffected participant will not interfere with the decision, we will simply assume that all network participants are in the decision making coalition.

We will now argue that any socially beneficial network expansion will benefit this coalition in the sense that all of its members could be made better off by some combination of the dispatch improvement and the allocation of the acquired rights.

The following proof is a formalization of this simple argument. If the expansion is undertaken by the coalition of all network participants, then by acquiring a set of rights that "encompasses"[17] the actual dispatch, their revenue from TCCs will equal the entire marketing surplus. This means they will collect the entire social net benefit since none is left for Poolco. Since they must have been collecting no more than the social net benefit before the expansion and since a beneficial expansion increases the social net benefit, the coalition must benefit from the expansion.

To begin with, let us define the social net benefit of trade on the network to be

$$NB = \sum(B_i - C_i)$$

where B_i is the benefit to demanders of power purchased at node *i*, and C_i is the cost to generators. This net benefit is divided between what we will call the trading surplus, TS, and what Wu et. al. have termed the marketing surplus, MS.

$$MS = \sum p_i\, y_i \quad \text{(Sum over nodes of price times quantity)}$$

$$NB = TS + MS$$

Once the set of TCCs, {TCC}, have been allocated in accordance with our feasibility constraint, there will be a congestion revenue, CR, consisting of all revenue collected on allocated TCCs.

[17] A set of rights encompasses a dispatch if the flows generated by dispatching the rights are at least as great, and in the same direction, as the actual flows on all links of the network.

By Hogan's revenue adequacy result, CR $\leq$ MS. If {TCC}[18] "encompasses" the dispatch, then CR=MS.

1. Before the expansion NB = TS + MS, and CR$\leq$ MS because {TCC} is feasible.
2. After the expansion $NB_1 = TS_1 + MS_1$.
3. $CR_1 = MS_1$ because the coalition chooses {TCC_1} to encompass the new dispatch.
4. NB_1 >NB because the expansion is beneficial.
5. $TS_1 + MS_1$ > TS + MS by substitution into 4..
6. $TS_1 + CR_1$ > TS + CR by substitution, so the coalition has benefitted.

Note that this proof assumes the rights set can be perfectly matched to the after-expansion dispatch, which is only possible if that dispatch is known in advance with certainty. It seems quite likely that the analogous statement about expected increases in benefit in an uncertain world, is not true.

4.6 Disallowing Detrimental Network Changes is Not Simple

One approach to solving the problem of an incentive that encourages detrimental network expansion is simply to disallow such expansions. While this does resolve the problem of detrimental expansions, that particular problem is only one manifestation of a much deeper problem. For coalitions that exclude some affected network participants, the incentive to make a particular network modification may be either too high or too low. That is, the reward to the partial coalition may be either greater than or less than the social net benefit of the modification. Much of this problem's origin lies in the economies of scale and scope

In spite of this shortcoming in the disallowance approach, disallowances could be an effective way of improving a necessarily imperfect system. For that reason this section explores possible rules for the disallowance of detrimental network expansions.

It should be noted that possible disallowance rules divide into two categories, 1) those that depend only on the physical network, and 2) those that depend on the expected dispatch. Since network dispatch is constantly changing and subject to uncertainty, decision rules in the first category would be more objective and simpler. Unfortunately, The following discussion makes

[18]We say a {TCC} encompasses the dispatch whenever it matches the dispatch, or when it is greater than or equal to the dispatch on every link. In this latter case, the revenue adequacy result assures us that the TCC will be greater than the dispatch only on links that are not congested. When comparing a {TCC} link by link with a dispatch, it is necessary to decompose the {TCC} in a manner that yields an unique set of link-based contracts. This is possible for any {TCC} and we refer to it as the canonical form of the contract set. This form can be found by dispatching the network in accordance with the {TCC} and then listing the set of TCCs that correspond to the actual flows on the network's links. Thus although Hogan's TCCs are not restricted to being link-based, this freedom does not lead to any increase in their flexibility, only in their convenience.

it apparent that this more desirable category does not include a rule that can discriminate between beneficial and detrimental expansions.

We have defined the particular expansion from the above example as a mixed expansion because it removes some feasible dispatches while adding others. Because the set of dispatches is two dimensional we can display them graphically to illustrate the concept of a mixed expansion. See previous figure 10.

A mixed expansion produces a set of dispatches which are newly *in*feasible as well as a set which are newly feasible. Consider the larger set of all dispatches which are feasible either before or after the expansion (the "super-network"), and let X be the optimal dispatch within this set. If X is in the newly infeasible set then the expansion is detrimental, while if X is in the newly feasible set it is beneficial. If X is in neither of these sets, the expansion is of no consequence, since it is feasible both before and after. The decision rule that suggests itself is to allow all and only those expansions for which X is in the newly feasible set of dispatches. Note that this is stronger than simply requiring that after expansion, the network will be optimally dispatched in a way that was previously infeasible.

The problem with assessing allowableness is that one must determine how the super-network would be dispatched under future supply and demand conditions. Analyzing the behavior of the network does not present any particular difficulty, but knowing the future of the network and the future of supply and demand conditions does. This difficulty is compounded by the interaction of long asset lifetime and the lumpiness [Baldick and Kahn, 1993a] of investment decisions. This interaction sometimes makes it desirable to expand the network in ways that are not immediately beneficial but that will be over the lifetime of the asset. Consequently the allowableness decision must be made by taking into account supply and demand conditions over the lifetime of the expansion.

Because the calculation of allowableness must be made over an extended time horizon, the definitions of the unexpanded and expanded network are greatly complicated. What must be compared is not two fixed networks, but two network expansion paths one in which the proposed expansion is not allowed and one in which it is.

By making short-term calculations and using intuition, the network administrator may be able to make a reasonable accurate determination of whether a particular expansion, will or will not be beneficial. However such an approach would probably not be satisfactory, because it would be impossible to assure all of the players of the administrator's neutrality and wisdom. For this reason an objective rule is needed.

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