Performance Based Regulation
For Independent Transmission Companies

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January 19, 2003
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Executive Summary

This paper explores regulation of an Independent Transmission Company (ITC) through Performance Based Regulation (PBR). It examines how the application of PBR, in the form of a price cap plan, can motivate the ITC to increase the benefits of competitive wholesale electricity markets for transmission customers. Transmission customers benefit from price cap regulation (PCR) because it aligns the ITC’s desire to provide a fair return to transmission asset owners with lowering short-term grid costs and least-cost management of reliability and grid expansion to meet growth in demand for transportation service. Thus, in keeping with the Federal Energy Regulatory Commission’s (FERC’s or Commission’s) desire for an Independent Transmission Provider (ITP), under a price cap, an ITC will focus on the market as a whole and will not unduly discriminate against market participants (generators and demand-side resources) and other transmission owners.

Transmission is a monopolistic service. The economics of transmission investment and the scope and scale economies of service provision ensure this will be the case for the foreseeable future. Therefore, transmission service (or rather transmission prices) must be regulated. Regulation of the transmission provider is a substitute for competition, and therefore, its core objective is to prevent the transmission provider from charging customers a price above what would be a competitive price for access and use. Transmission regulation aspires to do more than this, however. As the Commission’s proposal for Standard Market Design (SMD NOPR) suggests, regulation seeks to affect efficient operations and investment decisions by motivating the transmission provider to manage the system so it complements generation and distribution services and enables competition in wholesale electricity trade in the short run and over the long term.

Performance-based regulation is the implementation of rules and explicit financial incentives that encourage a regulated firm to achieve certain performance goals, while affording the firm significant discretion in determining how to achieve the goals. The firm can employ its superior knowledge of its business to achieve those goals. In this respect, PBR differs from cost of service regulation (COSR) by relying more on explicit financial incentives and by affording greater discretion to the ITC than a more strictly cost-based return of and on investment as with COSR.

The substitution of PCR for COSR offers the opportunity to make all primary interest groups better off: the regulated firm, customers, competitors and regulators. In theory, the ITC will bear greater financial risk under PCR in exchange for the prospect of earning a higher return on investment through efforts to increase its operating and investment efficiency. Consumers typically enjoy more pronounced price reductions over time than those reductions experienced historically under COSR.

Price caps have found their place in the regulation of network service providers of all types. For example, PCR has been used successfully in the telecommunications industry beginning with applications in the U.K. in 1989 and extending to applications of price cap plans in the U.S. during the mid to late 1990s. By 1991, the Federal Communications Commission (FCC) began regulating the incumbent local exchange carriers (ILECs) owned by the Bell Operating Companies (BOCs) under an alternative regulation system of price caps akin to what California adopted in 1989 for telecom.
Other state regulators followed suit. At the same time, smaller local exchange carriers that generated less revenue than the BOC-owned ILECs were given the option to continue to be regulated under COSR. In the past, many states also imposed profit sharing provisions in their price cap plans. Those provisions were intended to ensure that consumers benefited from rate decreases in conjunction with the companies’ increasing profits and to ensure that companies with unreasonably low earnings levels could receive relief in the form of rate increases.

Over the past 15 years, virtually all states have changed the method of regulating dominant local exchange carriers from COSR to PBR in the form of price cap plans. The overall regulatory trend in the U.S. has clearly been in the direction of price cap regulation for network industries. In 1995, dominant local exchange carriers in the U.S. were subject to some form of earnings-based regulation (i.e., earnings sharing mechanisms) in 35 states and price cap regulation in 9 states. In 2000, the corresponding values were 8 and 39. Similar changes in regulatory regimes have occurred in Australia, Europe and South America.

Price cap regulation places a cap (i.e., an upper limit) on the average price(s) that the regulated firm may charge for its services (or well-defined baskets of services). The actual prices the firm may charge are then limited by a formula to a calculated price cap index, which is typically adjusted over time (e.g., annually) for input price inflation and an offset designed to reflect productivity gains—the X-factor.

Economic theory provides the conceptual basis for price cap formulations that are consistent with a competitive market standard. The primary effect that market forces would have on a firm would be to limit the rate of growth of the firm’s profit, which is determined by relative rates of growth in its total revenue and its total costs. This relationship can be expressed in terms of the difference between the rates of growth in the input factor prices and a measure of total factor productivity. Thus, the price cap formula adjusts actual prices up by some inflation factor that mirrors input price growth rates (RPI) and adjusts prices down by a factor that accounts for growth in productivity (i.e., the so-called X factor). Thus, a price cap formulation is commonly known as RPI-X.

Implementing well-designed price caps entails three challenges for the regulator and the ITC: identifying products and services (and appropriate product bundles if multiple caps are developed), establishing initial costs to provide the products and services (i.e., a revenue requirement), and estimating the cost escalation (i.e., inflation) factor and the productivity (i.e., efficiency) factor. The inflation factor typically takes the form of a growth rate in an external inflation measure that cannot be affected by the management of the utility but that tracks the utilities’ expected cost changes closely. The X factor is the anticipated improvement in input factor efficiency the ITC is expected to achieve over the pricing cycle (typically five years). The X factor is typically set by the regulator at the outset of the pricing period but does not have to remain fixed during that period. Changes to the X factor over the pricing cycle can be agreed upon at the outset or can be introduced to reflect new information on external productivity trends in the industry. The X factor is typically calibrated using an estimate of the productivity trend of the industry over the pricing cycle, for example, using an estimate of the long-run productivity of the industry.
An efficient price cap for an ITC could be based on a two-part tariff reflecting the ITC’s variable costs and fixed costs. In general, price caps defined on two-part tariffs lead to more efficient pricing and investments than price caps defined on single-part prices. A two-part tariff for transmission service separates recovery of fixed (i.e., investment) costs from recovery of variable costs associated with use of the transmission system. The beauty of a price cap based on the two-part tariff is that it ties the recovery of fixed costs through the transmission access fee to the recovery of variable costs through the transmission usage fee. This presents the ITC with an explicit economic tradeoff between revenue from fixed fees (i.e., fixed cost recovery) and variable fees (i.e., the spot pricing of electricity for congestion relief, losses, and related ancillary services). If increases in transmission usage prices lead to a violation of the price cap constraint, transmission access prices would have to be reduced, placing recovery of the fixed cost component at risk. This pressures the ITC to take steps to better manage those variable costs or to make economic investments that will reduce them.

A price cap can be applied to a range of incremental models of ITC functionality, from full functionality assumed for the ITP in the SMD NOPR (see Table 1 in Appendix) to the functionality established for several ITCs in recent FERC orders (e.g., the TRANSLink order and the order on TransConnect’s innovative rate proposal). The benefits that a price cap program can provide are maximized when the ITC achieves ITP functionality because the ITC can fully internalize the grid externalities and the optimization over short-run operation costs and long-term grid enhancement opportunities. Nevertheless, variations on ITC functionality (in increments from minimum operations and maintenance to something short of an ITP) are part of the business environment and illustrate where the incentive tensions are most visible. Limits on the ITC’s functionality will reduce the size of the welfare benefits, but these limits are clearly part of the regulatory reality for transmission providers within RTOs dominated by ISOs functioning as ITPs.

Price caps can be designed for ITCs with less functionality than an ITP. And there will be many situations in which the ITC plays a subordinate role to the ITP or operates in a tiered approach to an ITP to serve a large subregion within the ITP footprint. In some instances the ITC may not be responsible for running a real-time spot market, acting as the provider of last resort (POLR) for ancillary services, or for managing congestion, but will still have responsibility for a subset of functions that help to determine transmission usage costs. In other cases, the ITC may be the default provider of real-time markets, reserve services and congestion management when the ITP is not in a position to perform such functions. Whatever subset of functions falls to the ITC can be included under a price cap to limit what the ITC can collect from customers through transmission usage and access fees and to link reward for its performance of those functions to recovery of transmission access fees.

The price cap based on a two-part tariff links operations and investment and should lead to efficient investment decisions. Under a price cap, an ITC would consider building a new line when the incremental cost of the line is less than the benefits of reduced transmission usage costs and less than the incremental cost of any other option to reduce transmission usage costs. If the incremental cost of either a generation or demand-side resource solution to a grid problem were smaller than the incremental cost of a new
high voltage line, the ITC, under a price cap plan, would opt for the non-wires solution. The result for the ITC is the same; the solution reduces transmission usage costs and therefore enables the ITC to earn a performance premium. The ITC should not favor a wires solution if by doing so it reduces the portion of the performance premium it can earn.\footnote{1}

Price cap plans for ITCs can provide a more efficient tool to address market power problems in wholesale markets. Congestion contributes to generators’ ability to exercise market power, and in some cases, generators may be in a position to affect the level of congestion in order to profit from the market power it affords them. Here is one instance where the “independence qua neutral party” view of the ITP has its drawbacks. The non-profit ISO has nothing at stake in combating market power except perhaps pride in performance; no profits are at risk. But the ITC with full functionality will have profits at risk in running the system under the price cap plan. Congestion costs, a major portion of transmission usage costs, will become a primary focus for the ITC. As manager of its system, the ITC will be in a position to take economic actions in real time as well as over the long term that will have the effect of mitigating market power and reduce the use of market monitoring algorithms that trigger intervention in spot market prices.

Since price cap plans can accommodate nearly any rate design, they can enable ITCs to move to pricing structures that are consistent with the FERC’s goal to eliminate rate pancaking. Moreover, they permit pricing structures that minimize inequitable cost shifting and revenue erosion for contributing asset owners, and enable the application of traditional rate design principles of cost causation and revenue accountability.

The Commission’s Order 2000 left open the possibility that an ITC could meet the definition of independent (i.e., market neutral) and qualify as an ITP, or at the very least be permitted to administer energy markets, so long as it had no commercial (financial) stake in generation or wholesale and retail sales. With that degree of separation, it could be argued (and was argued by TRANSLink and the Alliance Transco companies and National Grid) that an ITC would have no incentive to unfairly favor some wholesale transactions over others.

One goal of restructuring has been to establish a system operator and market manager (either jointly or separately) that will be independent of market participants and act in an unbiased manner with respect to short-term grid operations (particularly under SMD), efficient short-term resource use and decisions about optimizing long-term reliability, congestion management and grid expansion. The dominant solution applied to date in the U.S. has been to resort to an ISO-centered ITP. One characteristic of this model is that it separates operations and the long-term planning process from grid ownership and investment. While the ISO may be a neutral party, separation means that the regulator must find some motive other than profits to ensure that the ISO serves these public policy goals; separation by itself does not create incentives.\footnote{2}

\footnote{1} The incentives for the ITC to consider all options or to favor wires solutions only when they are the least cost solution are not as strong under COSR or when the ITC does not have the full functionality of an ITP. \footnote{2} The existing studies of efficiency comparisons of for-profit and not-for-profit firms in industries where they coexist suggest on balance that for-profit firms have an efficiency advantage. The studies show that the efficiency advantage stems from more efficient management, J. R. Boyce and A. Hollis, “Governance
The ISO-based ITP model short-circuits the profit motive that utility regulators have relied on for the past century to accomplish short-term and long-term public policy goals. Functional separation in the ISO-based ITP model to achieve market neutrality severs the dynamic link between the short-term (operational) and long-term (investment) functions that, when placed in the hands of an ITC, determine the firm’s profitability. Thus, with an ITC-centered ITP model, the link between short-term and long-term profitability can be harnessed by the regulator to get the ITC to operate in a market neutral way (with respect to market participants) and to discriminate among solutions to grid problems on the basis of social costs and benefits.\(^3\) The alternative, a strong reliance on market participants to invest in transmission facilities, runs afoul of the lack of independence (conflicts of interest) that motivated the separation of generation and transmission in the first place. Generators and load serving entities may have agendas that are in direct conflict with the objectives of transmission expansion or the elimination of congestion and the increase in competition. The Commission's orders have sought to create independence for short-term operations, but the same independence may need to be established for the longer term as well. The ITC can help solve that problem; the incentives under a price cap are even stronger.

Price cap regulation can help facilitate the transition from the old (vertically integrated industry) structure to standalone ITCs that may be consolidating the transmission assets coming from owners with strikingly different corporate structures (i.e., the differences can be as sharp as between vertically integrated utilities (VIUs), electric cooperatives and municipalities). The attractive feature of price cap plans is that they can accommodate almost any pricing structure that can be designed, so long as the structure does not lead to a violation of the cap. What is most valuable about PCR, in this regard, is that it permits repricing to take place smoothly during transition periods. That is, the ITC can move from zonal pricing to postage-stamp pricing if it desires (or was required to do by the Commission) without difficulty (even if it was inefficient to do so). An ITC can adopt license plate pricing or develop some hybrid pricing structure that incorporates more efficient, distance-sensitive elements such as that proposed by TRANSLink, LLC that involves highway pricing and zonal pricing.

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3 When the ISO operations are separated from asset ownership and investment capability, neither the ISO nor the ITC can make optimum tradeoffs between short-term and long-term behaviors that would affect the overall market surplus, and which would redound both to customers and to the profitability of the ITC. Combining these two functional categories enables a dynamic interaction that drives an ITC to seek ways to enhance profitability that simultaneously benefits customers (well beyond what can be achieved by a COSR model applied to a “rentier” of poles). A PBR regime would permit the regulator to achieve the focus on the market as a whole because the “market as a whole” means most efficient industry results, least cost, competition-mimicking results. The separation from market participants is not the issue, per se, it is efficient market outcomes—the balance between supply and demand, that is the objective. Independence is a transitional problem in the shift from vertical integration to disaggregation. The U.S. is perched on a ledge of ISO-managed VIU asset owners for entirely political reasons. But that model should only be a crutch until more complete vertical disaggregation has been achieved (even though evolving from a thoroughly entrenched ISO model will be difficult). With complete disaggregation sound regulatory policies (PBR) that try to mimic competitive outcomes that cannot be achieved through pure market mechanisms can be adopted.
A price cap plan for a fully functional ITC covers services associated with spot market activity (real time operations and possibly day ahead scheduling) as well as long-term planning and expansion. The ITC thus will want to focus on increasing the efficiency of the short-term market and the long-term market. The lowest prices for energy-based services that the ITC would be providing in real time will be achieved through a competitive spot market, so the ITC will want to do whatever it can to facilitate increases in the competitiveness of the spot market (through maximizing the transfer capacity of the existing grid, through the design of market rules or in terms of its operation of the system). The ITC would be in a position to know whether it can take steps to reduce the transmission usage costs in the day-ahead market given supply offers and demand bids. In addition, the ITC could take steps in managing the real-time to reduce usage costs (e.g., by increasing line ratings; redispaching the system to address situations that could enable generators to exercise market power). These actions would be transparent to the market and hence to the market monitor and the regulator.

The paper discusses how an ITC can be regulated under a price cap to perform with the full functionality of an ITP, or with any level of functionality, so that it focuses on the market as a whole and does not unduly discriminate against market participants (generators and demand management resources) and other transmission asset owners. Price cap regulation produces benefits for transmission customers because it aligns asset owners’ incentives with the goals of increasing the efficiency of the market, consumption and investment decisions. It motivates asset owners and their managers to take steps to protect the recovery of the investments by finding economic solutions to grid problems and to meeting reliability standards and growth in the demand for transmission capacity.

Applications of PBR and price cap plans should be considered with eyes wide open; they are not a panacea. However, there are strong public interest reasons for examining new regulatory approaches. A well-designed price cap plan that replaces COSR’s weaker incentives to stimulate investment in improved efficiency and investment in the grid with positive rewards for superior performance is desirable for market participants, transmission companies and regulators. A well-designed price cap plan stands a better chance of motivating desirable behavior than COSR. More efficient and creative ITC managers will take actions that benefit both transmission customers and shareholders. Furthermore, price caps can be implemented in all phases of the evolution to SMD. Now is the time to take actions to develop price cap plans for applications in the new industry structure that will ensure the transmission system remains a robust facilitator of competitive wholesale electricity markets.
1. Introduction

This paper explores regulation of an Independent Transmission Company (ITC) through Performance Based Regulation (PBR). It examines how the application of PBR, in the form of a price cap, motivates the ITC to increase the benefits of competitive wholesale electricity markets for transmission customers. Transmission customers benefit from price cap regulation because it aligns the ITC’s desire to provide a fair return to transmission asset owners and investors with lowering short-term grid costs and least-cost management of reliability and grid expansion to meet growth in demand for transportation service. Thus, in keeping with the Federal Energy Regulatory Commission’s (FERC’s or Commission’s) regulatory objectives for an Independent Transmission Provider (ITP), the ITC can, under a price cap, focus on the market as a whole and will not unduly discriminate against market participants (generators and demand side resources) and other transmission owners. Other important benefits of PBR include lower administrative and regulatory compliance costs.

Strong opposition to the ITC being granted the functionality of an ITP has arisen on two fronts as ITCs have begun to form. On one front, for example, Hogan, Chandley, and Ruff et al. base the thrust of their opposition to the ITC-centered ITP model on the premise that the ITC would unduly discriminate against market participants and exercise market power. From this they conclude that the ITC should not be awarded operational control or the greater functionality of an ITP; to do so would be to sacrifice efficiency they argue. Their analysis, such as it is, does not consider the implications of regulation using PBR and in fact declare that – while useful abroad – PBR is unsuited to use in the context of SMD.

Another front of resistance arises from the general trend toward replacing regulation with competition in as many segments of the industry as possible. This leads to the misguided notion that wires and non-wires services can be viewed as substitutes (in the short term), so that transmission can be encouraged to compete with generation and demand-side resources to set the real-time dispatch and nodal prices. It further encourages the belief that market-based responses to nodal pricing of congestion will spur much-needed investment in transmission infrastructure. From this belief some reach the conclusion that ITCs should be competing with all other market participants to

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expand the grid with a Regional Transmission Organization (RTO) or ITP “refereeing” the process. Together, these two notions lead some observers to treat regulated transmission utilities as second-tier players in the new world of standard market design. These notions run afoul of two immutable network characteristics: one, the transmission system and real-time service are monopolies (and will remain so for the foreseeable future) and therefore need to be regulated appropriately to achieve efficient short-term and long-term outcomes and two, significant network externalities undermine the incentives for market-driven investment.

This paper asserts that price cap regulation (PCR) offers an alternative to cost of service regulation (COSR) that paves the way for increased functionality for ITCs working alongside ITPs or as ITPs themselves. In addition, the full social benefits that can flow from the ITC operating as an ITP can be achieved. Regardless of the degree of functionality attained by the ITC, the conclusion is that the appropriate form of regulation is PBR, rather than COSR. Price cap regulation offers an answer to those who would believe that an ITC cannot achieve market neutrality and to those who would rely on competitive market solutions and ignore the economic implications of a monopoly network.

The solution lies in developing a price cap based on a two-part tariff. In general, price caps defined on two-part tariffs lead to more efficient pricing and investments than price caps defined on single-part prices. A two-part tariff for transmission service separates recovery of fixed (investment) costs from recovery of variable costs associated with use of the transmission system. The beauty of a price cap based on the two-part tariff is that it ties the recovery of fixed costs through a transmission access fee to the recovery of transmission usage costs. This presents the ITC with an explicit tradeoff between revenue from fixed fees (i.e., fixed cost recovery) and transmission usage fees (i.e., fees that are tied to the spot pricing of electricity for congestion relief, losses, and related ancillary services). When increases in transmission usage fees push the average price above the price cap constraint, transmission access fees get squeezed, placing the fixed cost share of the total capped price at risk. The ITC will be highly motivated to ensure that this does not happen.

The received view among many practitioners and academicians is that non-discrimination is achievable by placing responsibility for monopoly transmission functions in the hands of an agent with no interest in generation, distribution or marketing—an independent transmission provider. Under this view, an ITC also would be independent. A smaller set of practitioners believe that non-discrimination also requires the separation of the grid operations from transmission owners. Given that the monopoly function of real-time dispatch of demand and supply resources and the real-time spot market are one and the same, they conclude that it also makes sense to place the administration of the spot market (real-time market for certain and day-ahead markets most likely) in the hands of an ITP, so as to achieve economies of coordination. Combining grid operations with market administration to achieve economies of coordination, which is what it’s all about, makes just as much sense when the ITC

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8 See L. E. Ruff, op. cit.
9 This is the view taken in this paper
10 For example, Chandley, Hogan, Ruff et al.
operates as an ITP. And if the spot market prices are based on locational marginal (electricity) prices (LMPs), the ITP is then be able to ration transmission capacity to those who value it most highly through prices for transmission use founded upon differences in LMPs. In theory, the market-based pricing of transmission use can then become a foundation for market-driven investment in the grid when it is economical to do so. This, more or less, has been the model put into practice in the Northeastern ISO markets.

The Commission proposes in the SMD NOPR to achieve these goals by requiring all jurisdictional transmission-owning utilities to turn over control of their assets to an ITP. The ITP would be responsible for running day-ahead and real-time energy markets according to a clear-cut template, for allocating (i.e., selling) rights to the use of scarce transmission capacity and for coordinating and directing the transmission planning and expansion process. The critical question for those companies keen on participating in the transmission business is posed in the SMD NOPR: can a for-profit ITC be considered sufficiently independent of the market (i.e., market neutral) to qualify as an ITP?

ITCs can be allowed to assume full functionality as ITPs if they meet two tests: scope and configuration and market neutrality. An ITC’s independence of market participants, as defined in Order 2000, is assumed for this paper. Significant consolidation of regional transmission assets under an ITC’s control may be necessary before one will be large enough to manage regional markets. However, sufficiently large ITCs could perform all the functions of an ITP, and would be motivated to superior performance under a well-designed PBR. Such a PBR must provide the correct incentives to ensure that the ITC does not unfairly discriminate against generation, demand management or other transmission owners, (and to avoid other unintended consequences). This is a tall order, and there is no such PBR experience in the United States for ITCs, although there is extensive experience with PBR at retail and in the regulation in telecommunications markets. The experience in the electricity industry in the United Kingdom and elsewhere should point ITCs and regulators in the right direction. ITCs that seek greater functionality up to full ITP approval from FERC must therefore develop and present a workable PBR that addresses the concerns of those who favor an ISO-centered ITP. This paper outlines some of the basic considerations in achieving that objective.

The remainder of this paper is organized as follows. Section 2 covers the regulation of the ITC through PBR in the form of a price cap, discussing the economic rationale for and basic elements of a price cap. It also describes alternative forms of PBR. Section 3 discusses the elements of a price cap plan for an ITC with full functionality of an ITP and for an ITC with less responsibility. Section 4 details the benefits of price cap

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11 See the SMD NOPR for full discussion of the market design.
12 There is no difference between an ITC and a Transco today, so the term ITC will be used broadly in this paper. The key distinction at one time was that the Transco would operate spot markets and the ITC would not.
13 However, PBR can reinforce the independence of the ITC, as discussed below.
regulation for ITCs, which includes efficiency in operations, in investment and in management, market power mitigation, efficient pricing and facilitation of the transition from the traditional vertically integrated utility structure to the SMD in a fully independent transmission sector. Section 5 outlines the steps and issues that must be addressed to implement a price cap plan. Section 6 offers conclusions.

2. Regulation of the ITC

2.1 Transmission Regulation for Efficient Markets and Investment

Transmission is a monopolistic service. The economics of transmission investment and the economies of scope and scale of service provision ensure this will be the case for some time to come. Therefore, transmission service (i.e., prices) must be regulated.\(^{15}\) Regulation of the transmission provider is a substitute for competition, and therefore, its core objective is to prevent the transmission provider from charging customers a price above what would be the competitive price for access and use. Transmission regulation aspires to do more than this, however. As the SMD NOPR suggests, the Commission is also seeking to affect efficient operations and investment decisions by motivating the transmission provider to manage the system so it complements generation and distribution and enables competition in wholesale electricity trade in the short run and over the long term.\(^{16}\)

The challenges to regulation of transmission arise in three areas, regardless of the structure of ownership. First, transmission is subject to network externalities associated with real time operations such as loop flow and congestion and losses (every action on the system affects every other action). This makes it difficult to assign responsibility for the marginal real-time system costs caused by transmission users. In turn, this makes defining and assigning property rights difficult, especially if use of the grid is measured inaccurately or not at all as it is today in some parts of the grid. Therefore, it makes relying on market-based investment and participant-funded transmission expansion much more challenging.

Second, investment in transmission networks exhibit significant scale and scope economies, lumpiness and externality effects.\(^{17}\) Scale effects in transmission occur because the incremental cost to double the size of a new line may significantly lower the average cost per MW compared to a line only half the size. In addition, grid expansion comes in fixed sizes; additions cannot be made in small increments of 1 MW to match

\(^{15}\) Transmission service is more than putting up wires and connecting them to generators. It is composed of operational control of the grid and the scheduling and dispatch of generation in real time, wires maintenance and management of the long-term expansion planning and investment process. These elements could not be efficiently provided through a competitive market. However, procurement of a monopoly provider could be obtained through a competitive bidding process. Regulation would still be necessary once the provider was chosen, however. And PBR would offer the superior model in this regard. See S. Hunt, “Making Competition Work In Electricity,” John Wiley & Sons, (Finance Series), 2002.

\(^{16}\) This means that transmission is operated so it increases competition among generators and thereby reduces market power for both generators and buyers (i.e., monopoly or oligopoly power for generators and monopsony or oligopsony power for buyers).

\(^{17}\) Economies of scale are present when the average total cost of production falls as the number of units produced increases (or the productive capacity increases). Economies of scope exist when an increase in the production of one product leads to a reduction in the production cost of another.
demand of individual customers. This means that many efficiently sized market-based transmission investment projects are too large and hence too risky for any single market participant. Furthermore, the benefits (i.e., the positive externalities) associated with an increase in the transfer capability of the grid are nearly universally enjoyed. Together these two effects lead to free rider and “last straw” problems for transmission investment. This means that the success of market approaches to network expansion planning and investment depend on market participants receiving a strong (clear) price signal about the incremental cost of transmission use, on the formation of strong coalitions of market participant investors. The jurisdictional bifurcation of regulatory authority (the FERC over rates and the states over siting) coupled with the states’ worry that native load customers will be unfairly saddled with interstate transmission facilities costs, means that the FERC’s market-based approach to investment depends critically on a successful consensual process among market participants and the states within a region and between regions. This is a tall order for a market to fill, and consequently, market-based approaches may only be successful in limited instances where these barriers can be overcome, such as with merchant development of direct current (DC) lines.

Third, because of the strong network externalities associated with investments that both widen and deepen the transfer capability of the system (especially the high voltage system), the expansion planning and investment process suffers from a free rider problem. Thus, relying on market-based investment (i.e., merchant and participant funded investment) as the primary source of system improvements will be subject to serious market failure. While congestion revenue rights (CRRs) may be an incentive for some market participants to invest in transmission infrastructure, they must be discounted in the investment decision process because CRR values derive from congestion-induced LMP differences, which the grid expansion would obviate. Investment may still be economically attractive if it allows cheaper power from remote generators to substitute for more expensive local supply and earn higher profits from supply scarcity (i.e., capture some scarcity rents). But this also means that there are some strong incentives for free riding. If a cheap generator benefits from the elimination of congestion, it may be better off waiting for some other market participant to build transmission first, thus saving the generator the cost of building. However, if all market participants take that attitude, the result could be a stalemate and little or nothing gets built.

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18 The “free rider” problem occurs in cases of public goods where market participants are able to consume a product or take services without paying an appropriate price for them. The problem provides incentives to consumers of public goods to intentionally understate the true value to them in order to reduce the price they must pay for it. The “last straw” problem occurs when new customers are added to the grid and the system’s capacity reaches a limit (becomes congested at particular times) restricting use unless the system is upgraded. If the new customers are held responsible for paying for the upgrade, a “last man” problem arises that could lead to under-investment in the grid. Latecomers don’t want to pay the larger price for their incremental use when many others potentially can benefit from the expansion. This problem can be solved in part through reasonable customer contribution policies and tradable Congestion Revenue Rights allocation.

19 Optimal transmission expansion would not eliminate all congestion, but only congestion up to the point that the incremental cost of the last MW of capacity constructed equaled the incremental reduction in congestion costs of that additional MW of capacity.

20 The majority of generators and marketers have placed their bets on the generation solution. They have invested billions in power plants that are located where they do little to relieve the urban scarcity and much to aggravate the rural plenty (i.e., to alleviate congestion). Many of these investments challenge the
2.2 Regulatory Tradeoffs

Since transmission operations and assets are and will remain monopolistic, transmission service and providers must be regulated. However, the challenges of regulating the monopoly grid subject to externalities, free rider and last straw problems require several tradeoffs. First, how can transmission service providers be motivated to offer nondiscriminatory access to the grid? So far, the preferred approach in the U.S. has been to separate structurally the control and operations of the grid and asset ownership to ensure the system operator does not unduly discriminate among or against market participants and other transmission owners. Thus, this has spawned the not-for-profit ISO-centered ITP model promoted by many industry observers, the SMD NOPR and recent FERC orders on ITC participation in regional markets.

But this is not the remedy pursued in the rest of the world. The tradeoff is that structural separation unnecessarily sacrifices the efficiency of integrated ownership and operations to achieve nondiscrimination. A single monopoly provider of operations and investment can internalize many, if not all, of the externality problems that undercut the effectiveness of a market-driven approach to transmission investment and the bifurcation of ownership and grid control. The monopoly owner-operator – if properly regulated – can provide both open access and be motivated to make appropriate investments in the grid and other competing options to address grid problems and needs. With absolute vertical disaggregation, the externalities (free rider and last straw problems) can lead the market to under-invest in transmission for reliability and economic purposes. Structural separation to achieve independence (i.e., neutrality vis-à-vis the market) severs a portion of the connection between the motivations of asset owners for a return on their investment (and the fiduciary responsibility of ITC managers to protect that investment) and the operations of the grid that most affects the costs of transmission use.

The regulator can harness such connections to induce the ITC to perform all functions of an ITP in an economically neutral manner, which is the real objective of separation and the heart of the debate over independence of the system operator from market participants. Such connections cannot be harnessed in the ISO-based ITP model because the ISO does not (and cannot by definition) own assets. The ISO managers have no assets at risk or owners’ interests to protect. Consequently, traditional forms of rate regulation, such as COSR (or even more effective forms such as PBR and price cap plans), cannot be applied readily to regulate the monopoly ISO itself and to create incentives for the ISO to serve the public interest beyond those associated with its independence, namely its market neutrality. There must be other incentive structures developed that affect individual management decisions and align ISO management with the public interest. There is no theoretical or empirical evidence that demonstrates performance incentive structures for not-for-profit entities can be developed that will lead

regulated transmission sector to fix the congestion by enhancing AC transfer capacity. The experience of most transmission owning companies, however, is that all investments are local and incremental. Thus, it has been unusual for utilities to develop long-distance transmission solutions. The few long distance investments that have been made in the past have come from entities such as Hydro-Quebec or BC Hydro that had a specific source of low-cost power and were willing to invest significant sums to transport that power to markets, still motivated by the interests of the vertically integrated utility.

to performance that is superior to that of a for-profit entity operating in a competitive environment or operating as if it were subject to competition (as in the case of price cap regulation of an ITC).  

Second, as Graves and Stoft point out, ‘regulators have to make a decision about the pricing regime.’  

The difficulties in choosing a transmission-pricing regime stem from a fundamental regulatory trade-off: efficiency versus ‘rent extraction.’ The traditional view is that the regulator’s goal is to eliminate monopoly rents, at least under expected operations. The current academic view is that extracting all possible rent from the regulated firm is undesirable because it eliminates all incentives for the utility to improve its efficiency. In other words, if regulators were to achieve their goal of perfect (and unconditional) COSR, it would result in poor performance because all of the firm’s incentives to improve would have been eliminated. Fortunately, COSR and rent extraction have been pursued with less vigor by regulators, with subsequent benefits for the efficiency side of the tradeoff. This stands as a cautionary point for regulators considering adopting PBR as an alternative to COSR, because aggressive pursuit of rent extraction will undermine the efficiency properties of PBR as well.

2.3 Performance-Based Regulation

Performance-based regulation is the implementation of rules and explicit financial incentives that encourage a regulated firm to achieve certain performance goals, while affording the firm significant discretion in determining how to achieve the goals. The firm can employ its superior knowledge of its operating environment to achieve those goals. In this respect, PBR differs from COSR by relying more on explicit financial incentives and by affording greater discretion to the regulated firm than on a more strictly cost-based return of and on investment as with COSR.

Performance-based regulation offers many benefits over COSR. The most important of these is that, under PBR plans, regulated firms, ITCs in particular, possess the necessary incentives to operate and invest efficiently, which they do not possess entirely under traditional COSR, and are motivated to operate in a non-discriminatory fashion with respect to market participants (because they will choose the lowest cost option, regardless of source). In addition, such plans provide the regulated company with the ability to respond to competitive pressures. When the firm is not subject to direct competition, as in the transmission business by and large, it is able to operate as if it

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22 The existing studies of efficiency comparisons of for-profit and not-for-profit firms in industries where they coexist suggest on balance that for-profit firms have an efficiency advantage. The studies show that the efficiency advantage stems from more efficient management. R. Boyce and A. Hollis, “Governance of Electricity Transmission Systems,” Department of Economics, University of Calgary, Calgary, Alberta CA, August 2001, Table 2. p. 13.


24 Rent extraction is the process by which regulators secure for customers a share of any profits the utility earns above what the regulator deems to be normal competitive levels.


26 There are exceptions of course. Merchant transmission investment in and construction of DC ties represents a form of competition to the utility-based expansion of the AC network. One upgrade to the AC network may also compete with another upgrade in some circumstances. System reliability is not
were. This is because the price cap acts as a surrogate competitive market price ceiling, giving the firm the discretion to cut costs to increase profits and make short-term and long-term economic tradeoffs. In general, aggregate consumer welfare can be further increased because PBR, in the form of a price cap plan, can afford the regulated firm the opportunity to price services efficiently to different customer groups who value the services differently. With the ITC’s average price capped, the ITC is free to set actual tariffed rates for services at any level so long as the average prices customers pay do not violate the price constraint (see Section 3 for more details). Thus, the ITC can lower prices for some customers and raise prices for others, (following a cost causation principle, for example). PBR can also lead to a reduction in various administrative and compliance costs.

Performance-based regulation has become increasingly popular in many regulated industries throughout the world. In the U.S., PBR has been employed extensively in the telecommunications industry for nearly a decade. Over 40 states employ PBR to regulate the intrastate operations of local exchange carriers. At least 28 electric utilities in 16 states currently operate or have recently operated under some form of broad-based PBR for retail service (discussed in Section 2.4).

Alternative types of PBR include ‘return-on-equity’ (ROE) ranges, performance-linked allowed ROEs, return-sharing between customers and shareholders, price caps and social contract regulation. Many PBR programs involve combinations of these forms (discussed in Section 2.6).

The general objectives of PBR are to:

• improve cost and price performance,
• maintain and improve service quality,
• encourage effective expansion (i.e., maximize the gains to the market from network expansion or enhancement), and
• provide the service provider with an opportunity to remain competitive in capital markets and
• in the case of transmission, fortify the market neutral behavior of the ITC (discussed further in Section 4.2).

When PBR is applied to transmission service, which is subject to externality effects, the objective is to encourage the transmission service provider to make customers necessarily optimized uniquely. And transmission does compete with generation and demand resources to some extent in the long term in so far as a line upgrade or a new line that increases transfer capacity can enable distant generation to compete with local generation to serve a load center. Naturally, regulators will want to encourage the most economical solutions to grid problems and growth in grid demand. While the primary function of transmission and transmission upgrades is to enable distant generation to compete with local generation or even demand-side resource options, thus supporting expanding markets, transmission enhancements can also substitute for some ancillary services in certain circumstances, for example in providing voltage support.

better off by finding ways to lower the cost of delivered energy (i.e., to increase consumers’ welfare, also known as market surplus). Under PBR, the ITC as a residual claimant would be rewarded for increasing consumer welfare by being allowed to retain a portion of the surplus it creates and sharing the rest with customers. Under COSR, an ITC also may be motivated between rate cases to reduce costs below projected levels to increase its rate of return, but the firm would not voluntarily share a portion of those reductions with customers (although they may be asked to give them up going forward in the next rate case, which also acts as a disincentive to reduce costs).

The market surplus is composed of the difference between the consumers’ valuation of the service and the market price, on the one hand, and the difference between the market price and the cost of production, on the other hand. In Figure 1, which illustrates market surplus, the horizontal line labeled P represents the market-clearing price (per unit) for the good. The Q on the axis labeled Quantity represents the market-clearing quantity. Consumer surplus is the triangular area labeled A, which represents the difference between what consumers are willing to pay for a good (the value of the good) and what they actually pay. The producer surplus is the triangular area labeled B, which is the difference between the cost to produce the good and the market-clearing price. The sum of the two areas represents the market surplus.

Assume that the market-clearing price P represents the delivered cost of energy (i.e., it includes the costs of electricity production and transmission). The ITP (an ISO or an ITC) can lower P in a number of ways. For example, it could decrease the cost of transmission use (i.e., decreasing the cost of congestion, losses or ancillary services) by improving operational efficiency. It could find ways to lower the cost of transmission access and therefore lower P.

If generators were paying these costs and had to recover

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28 The cost of delivered energy that the transmission service provider has some influence over is the sum of the wholesale cost of electricity (based on the spot price), and the cost of transmission access and transmission use, which includes congestion cost, losses and ancillary service costs. These latter are a significant component of the marginal costs of transmission.

29 It can be seen that some consumers place a higher value than others and that some producers can produce for less than others, hence the slope of each curve.

30 For example, the ITC may find other uses for its towers and lines that can be sold to recover capital costs, and thus reduce the amount of revenue that must be recovered from transmission customers through access fees. If all generators pay an access fee, the fee is a cost of business that must be recovered in the price they receive for power and hence that fee affects the market-clearing price. If the access fee is lowered, competition among suppliers will force them to pass that cost reduction on to their customers, thereby lowering the market-clearing price.

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them through the market price, this would then decrease generators’ input costs and shift the supply curve down. With all else constant, the market-clearing price \( P \) would decrease and the consumer surplus, area A, would increase.

A well-designed PBR program encourages an ITC to find ways to expand transmission customers’ welfare (i.e., areas A and B); that is, to lower the cost of wires and energy-based transmission services and to figure out how to expand transmission capacity to increase the degree of competition in the spot and bilateral markets (or reduce transmission constraints that limit competition in these markets so as to reduce the usage costs). Thus, the ITC, under a PBR program, would be motivated to seek ways to lower the costs of transmission service and the overall delivered cost of energy that includes congestion costs, losses, ancillary service costs, and spot market prices including the impacts of generator market power.\(^{31}\)

Switching from COSR to PBR is not without challenges, however. Designing incentives that achieve all of the goals well requires addressing a number of problems. A well-designed PBR needs to:

- avoid inefficient reductions in operating and maintenance (O&M) costs that lead to reduce system reliability or safety,
- avoid inefficient investment in transmission facilities,
- avoid incenting ITC managers to emphasize particular goals at the expense of others,
- allow the ITC pricing flexibility so as not to reduce the benefits for consumers, and
- avoid undermining the cost-reducing incentives of the PBR by seeking to extract excessive amounts of rent from the ITC.

In theory, the introduction of PBR should also reduce regulatory risk for the ITC, and thereby increase its competitiveness in capital markets, especially with a price cap program. However, in practice, regulatory risk is not always reduced. Regulators can take steps to reduce the short-run profitability of the ITC (i.e., through more aggressive rent extraction) and thereby undermine the long-run incentive properties of a price cap plan. For example, regulators could set the productivity factor in the price cap plan too high (discussed in Section 2.4). In hybrid programs that combine elements of price and earnings regulation, the regulator could cap prices for selected services below incremental costs and offer to make up shortfalls through cost-based side payments or subsidies, thus enabling the regulator to engage in a form of earnings regulation within a price cap regime. Again, this weakens the positive incentive properties of PCR.

### 2.4 Price Cap Regulation

The substitution of PCR for COSR offers the opportunity to make all primary interest groups better off: the regulated firm, customers, competitors and regulators. In theory, the ITC will bear greater risk under PCR in exchange for the prospect of earning a

\(^{31}\) This includes expanding the transmission system that, in effect, shifts the supply curve to the right relative to demand and lowers the market-clearing price. This rightward shift can encompass an increase in the supply of generation to a load pocket for spot energy, bilateral contracts and ancillary services. Consequently, some of the market price reduction can result from the mitigation of supplier market power.
higher return on investment through efforts to increase its operating and investment efficiency. Consumers typically enjoy price reductions over time more pronounced than those experienced historically under COSR.\textsuperscript{32} For example, price cap regulation was introduced in 1989 as an improvement to the problems of yardstick regulation of distribution utilities in Chile. Empirical analysis of the experience suggests that price cap regulation has resulted in lower costs (i.e., the ratio of reported costs to revenues has fallen).\textsuperscript{33}

Consumers also can enjoy benefits through repricing by the utility because price caps grant additional pricing flexibility that enables the firm to compete more effectively in markets for its services that become increasingly more competitive.\textsuperscript{34} Repricing (i.e., tariff restructuring) took place in both the telecommunications (in the US and the UK) and natural gas industries (in the UK) with benefits flowing to consumers from increased efficiency that this produced (i.e., reduction in or elimination of inter-class and intra-class cross-subsidies).

Regulators benefit in several ways. First, regulators are in a position to negotiate defined benefit packages for customers in exchange for moving from COSR to PCR.

\textsuperscript{32}The empirical record on this last point has not been uniform given that initial price cap designs have invariably required adjustments to bring actual benefits to consumers in line with theoretical predictions. The experiences in the rest of the world, the UK for example, should provide tremendous insights into appropriate designs for the US transmission sector. The introduction in 1989 of price cap regulation for privatized water companies and the regional electric distribution utilities (RECs) in the U.K. resulted in over-investment and a slight overall increase in operating costs during the first pricing cycle for the water utilities and large profits for the RECs because the price caps were overly generous based on underestimates of the REC's scope for reducing costs. Subsequent cycles have seen the regulators reset the inflation and X factors and seek other ways to tighten the cap and capture more of the benefits of cost reductions for consumers. See C. van der Berg, "Water Privatization and Regulation in England and Wales," \textit{Public Policy for the Private Sector}, The World Bank Group, Note No. 115, May 1997 and R. Green, "Has Price Cap Regulation of U.K. Utilities Been a Success?" \textit{Public Policy for the Private Sector}, The World Bank Group, Note No. 132, November 1997.

\textsuperscript{33}That price caps are beneficial for consumers is supported empirically. Interstate telephone customers have realized savings under price cap regulation. From 1991 to 1996, price caps imposed by the FCC resulted in $9 billion in savings to consumers. Adjusted for inflation over that period, the savings would have actually been $19 billion or a 37 percent decrease in real prices. Further, not only have interstate prices fallen, but companies operating under price caps have also benefited from higher earnings. See Comments of the United States Telephone Association, "In the Matter of Access Charge Reform," FCC Docket No. 96-262, filed January 29, 1997, and "Trends in Telephone Service," FCC, August 2001, Table 8.2. There is also evidence that local telephone services prices are not increasing as fast as they had been under COSR. Consumers' local telephone bills increased 7.0 percent annually from 1978 to 1991, compared to 4.7 percent for the Consumer Price Index (all items). In the last ten years, however, telephone prices have increased only 1.8 percent, while the CPI has increased 2.7 percent. In other words, telephone prices increased over 2 percent faster than other consumer prices under COSR between 1978 and 1991, but have fallen nearly 1 percent in real terms since 1991 under PCR. Thus, price caps appear to add a 3 percent savings on total residential bills, and if interstate line charges are excluded from the analysis, price caps appear to have reduced the local charges on residential bills by 2 percent per year.

\textsuperscript{34}Even though transmission service is monopolistic in the short term, demand for transmission capacity and services is not without substitutes in the long term (the period economists refer to as long enough for everything to be changeable). Increasingly, customers have self-generation options (i.e., distributed generation) that could significantly reduce or eliminate altogether their demand for transmission service or at least change the pattern of power flows. Long-distance transmission also competes in the long run with gas pipeline transportation and storage services.
These benefit packages can entail various combinations of bill credits, rate freezes, refunds and infrastructure modernization. Regulators can use (and have used in the telecommunications sector) a shift to PCR as an opportunity to win benefits for consumers. Second, the regulator benefits administratively from more streamlined regulation and from the fact that she no longer has to micromanage the firm’s operations. In addition, the regulator can structure the benefits package to demonstrate benefits to her constituency. Finally, because PCR severs the direct link between costs and prices that exists under COSR, competitors benefit from PCR because the regulated firm has neither the incentive to misreport the nature of its costs nor the ability to true-up earnings should its rate of return fall below pre-specified levels. Hence, unlike COSR, PCR affords the regulated firm little or no protection from losses due to competition or poor management decisions.

**Economic Rationale for Price Caps**

The Commission places great confidence in market-driven (i.e., competitive) solutions to grid problems and investment. And for that very reason it should endorse PCR. As stated in the NOPR, “The ability of individual market participants to see the economics of possible solutions and make market-driven decisions concerning the addition of infrastructure is the fundamental mechanism that induces efficient investment under Standard Market Design.” The competitive market standard established by the Commission in the NOPR has widespread appeal and is one that can draw on established economic principles and measurement techniques. But a pure market-based approach to grid investment is subject to market failure problems (discussed in Section 2). The purpose of PCR, as with many forms of regulation, is to replicate the discipline that market forces would impose on the ITC if it were subject to competition. Therefore, PCR for ITCs is consistent with this competitive market standard because the underlying economic rationale for PCR is that it simulates the movement in an ITC’s prices that would occur if the markets for its services were competitive.

Economic theory provides the conceptual basis for several price cap formulations that are consistent with a competitive market standard. The primary effect that market forces would have on a firm would be to limit the rate of growth of the firm’s profit. A firm’s profit is the difference between its total revenue and its total costs. Thus, the rate of growth of the firm’s profit is determined by the relative rates of growth in its total revenue and its total costs, which in turn, depend on the rate of growth in the output prices (i.e., service prices) and the rate of growth in the input factor prices. This relationship can be expressed in terms of the difference between the rates of growth in the input factor prices and a measure of total factor productivity. Thus the price cap formula

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36 This is also referred to as “rent extraction.” Refer to footnote 24 for definition.

37 The regulator under COSR must be vigilant of the firm’s operations and its costs. The ITC would be motivated to misreport its costs because cost recovery is subject to regulatory risk, whereas under PBR, the ITC has no incentive to misreport because the link between costs, revenues and profits has been severed.

38 SMD NOPR, P 337.
adjusts actual prices up by some inflation factor that mirrors input price growth rates and adjusts prices down by a factor that accounts for growth in productivity.

If an ITC were operating in a perfectly competitive industry, it would only earn profits at a normal level, just sufficient to recover a competitive return on investment in infrastructure. In the long run, an ITC in a perfectly competitive industry would not be able to earn extra-normal profits. The theory provides a useful guide to the design of PCR plans. A good PCR plan will seek to adjust the rate of growth in prices through these inflation and discount factors that will restrict the ITC’s profits to a normal (i.e., competitive) level. This is the central theoretical result that underlies price cap specifications. The power of this result depends on the reasonableness of its key substantive assumption: that cost grows at the same rate as revenue over time. The assumption is not literally true at each instant but is often reasonable in the long run. How well regulators tune these two factors will dictate the success of the PBR over time.

Acceptance of Price Cap Regulation

Price caps have found their place in the regulation of network service providers of all kinds. For example, PCR has been used successfully in the telecommunications industry beginning with applications in the U.K. in 1989 and extending to applications of price cap plans in the U.S. during the mid to late 1990s.

By 1991, the Federal Communications Commission (FCC) began regulating the incumbent local exchange carriers (ILECs) owned by the Bell Operating Companies (BOCs) under an alternative regulation system of price caps akin to what California adopted in 1989. State regulators followed suit. At the same time, smaller local exchange carriers that generated less revenue than the BOC-owned ILECs were given the option to continue to be regulated under COSR. In the past, many states also imposed profit sharing provisions in their price cap plans. Those provisions were intended to ensure that consumers benefited from rate decreases in conjunction with the companies’ increasing profits and to ensure that companies with unreasonably low earnings levels could receive relief in the form of rate increases that would enhance earnings.

Over the past 15 years, virtually all states have changed the method of regulating dominant local exchange carriers from COSR to PBR (in the form of PCR). The overall regulatory trend in the U.S. has clearly been in the direction of price cap regulation. In 1995, dominant local exchange carriers in the United States were subject to some form of earnings-based regulation (i.e., earnings sharing mechanisms) in 35 states and price cap regulation in 9 states. In 2000, the corresponding values were 8 and 39, respectively. Similar changes in regulatory regimes have occurred in Australia, Europe and South America.

Inspired by the relative success of price caps in telecommunications, state regulators have extended PCR to Local Distribution Companies (LDCs) in the natural gas industry and to electricity distribution utilities in the U.S. PBR plans have been adopted for LDCs in at least 15 states since the early 1990s.

Elsewhere in the world, price cap regulation has been in favor for some time. For example, price cap regulation has been in place for both local water and electricity distribution companies in England and Wales since 1989. The initial problems with price caps in the U.K., in which the companies earned profits that regulators believed were excessive, were ironed out over time through changes to the price cap formulas. Hence, for example, the price caps for the water industry have been successful in providing incentives for cost reductions. In fact, after the 1994-1999 regulatory period, some companies achieved cost savings up to 20 percent in operational costs and 15 percent in capital expenditure, in contrast to the cost increases that occurred during the first five-year pricing cycle. Price cap regulation of transmission and distribution has been introduced in Australia as part of the national electricity reform. The form of the price cap is similar to that adopted in the United Kingdom. Price cap plans have also been established for transmission and distribution utilities in Argentina.

**Price Cap Basics**

Price cap regulation places an upper limit on the average price(s) that the regulated firm may charge customers for its services. The average price(s) the ITC can charge are regularly (usually annually) adjusted by a price cap index formula to reflect at least two types of changes: increases in the firm’s efficiency and increases in input costs. Anticipated efficiency improvements are proxied by changes in a measure of the firm’s productivity (termed the X factor); changes in input costs are typically represented by some general index of input price inflation (termed the I factor).

The challenge for the regulator is to properly assess the X and I factors. If the X factor is overly ambitious in lowering the rate of average price increase, it will act as a penalty and the resulting regulatory rent extraction will reduce the firm’s incentive to provide services more efficiently and focus it more on economic survival. If the price escalation factor is higher than the rate of increase in input costs, the firm will earn too high a return and again the ITC may not focus on improving service efficiency.

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40 Other adjustments can be made to actual prices over the price cycle, such as so-called Z factors, adjustments for a wide range of factors other than inflation and productivity factors. See M. Schmitz, *Performance-Based Rate Making: Theory and Practice*, Public Utilities Reports, Inc., May 2000, for discussion of Z factors.

41 The X-factor in a price cap index formula is the minimum rate at which prices for regulated services must fall on an annual basis after adjusting for inflation. The X-factor is designed in part to reflect the degree to which productivity growth and input price changes diverge from those realized in the general economy.

42 The annual changes are adjusted according to a price cap index formula, where the productivity gains, the X-factor, are subtracted from price escalation factor (i.e., input price inflation factor) I. Thus, next year's price is equal to last year's price adjusted for the difference between price inflation less productivity gains. In its simplest terms, the price cap formula is written as: \( P_t \leq P_{t-1} \times (1 + I - X) \), where \( P_t \) is the average price set for the current time period, \( P_{t-1} \) is the average price set for the previous time period, I is a price escalation factor that represents an estimated percentage change in costs of the firm's inputs, and X is an estimate of the percentage increase in the firm's output productivity, (e.g., increases in the efficiency of labor, capital and other input factors of production).

43 The ITC may feel pressured to reduce costs in ways that also reduce service quality or reliability.
Price Cap Index Adjustment Factors

The heart of the price cap index is the price escalation factor, I, that tracks the changes in the ITC’s input costs. The price escalation factor typically takes the form of a growth rate in an external inflation measure that cannot be affected by the management of the utility (or not strongly affected by management decisions).

Naturally, if this price escalation factor is not correctly specified, the entire process and the potential benefits to the ITC and its customers may be harmed. The goal is to set the index so that actual annual price changes closely track increases in actual input costs. If the index is set too high, the ITC’s prices increase faster than actual costs, the ITC’s profits rise at a rate that would be considered by the regulator to be unreasonably high, and customers are made worse off; ITC management may also have weaker incentives to lower input costs. If the index is set too low, ITC prices increase more slowly than actual input costs, and ITC profits fall below what would be considered a reasonable level. The result is that the ITC is either pushed to “cut costs” inappropriately, or has its financial viability threatened, which can also undermine investment incentives or reduce the ITC’s competitiveness in capital markets. Regulators may be tempted to keep short-term price changes below input costs increases, but this is a regulatory rent extraction that will weaken the ITC’s incentive to serve customers, because regardless of what it does, the ITC will realize that it cannot improve the return to shareholders. Consequently, identifying an appropriate price escalation factor is important and a challenge in formulating the price cap index. More work will need to be done in this area for transmission.

The second, equally important, component of the price cap is the productivity factor, called the X factor. The X factor is the anticipated improvement in input factor efficiency the ITC is expected to achieve over the pricing cycle (typically five years). The X factor is typically set by the regulator at the outset of the pricing period and can also change each time the inflation factor changes, but does not have to remain fixed during that period. Changes to the X factor over the pricing cycle can be agreed upon at the outset or can be introduced to reflect new information on external productivity trends in the industry. The X factor is typically calibrated using an estimate of the productivity trend of the industry over the pricing cycle, for example, using an estimate of the long-run productivity of the industry.\(^{44}\)

A higher annual productivity discount provides greater benefits for customers and increases the pressure on the ITC to find reductions in its costs or improvements in input productivity. At the same time, too steep an X factor causes the firm to reduce its search

\(^{44}\) The X factor traditionally has been based on the estimation of long-run Total Factor Productivity (TFP) for the industry. Total Factor Productivity is defined as the difference between growth in a weighted average of factor input quantities and the growth in a weighted average of output quantities. The TFP calculations are based on a representative sample of the utilities that provide services covered by the price cap plan (i.e., other ITCs or similar firms). Calculating TFP for a multi-product firm, such as a multifunction ITC becomes more difficult, and for that reason, use of TFPs has diminished in popularity in PCR applications in other industries. The TFP-based X factor often can fail to accurately measure the productivity of a specific company, accurately forecast productivity gains based on historical trends, properly reflect capital versus labor productivity gains and properly differentiate scale economies from management initiatives.
for improvements because whatever it does, it cannot effectively further reduce costs or increase efficiency. The X factor operates as an offset against the price escalation factor, slowing the rate of increase of prices, and also determines in part how the benefits of reductions in costs or increases in input factor productivity can be shared between the ITC and its customers.

While the literature provides useful discussions of the advantages and disadvantages of the applications of PCR and offers useful insights on the general framework for price cap designs, it offers little guidance on the computation of the X factor that determines the rate at which inflation adjusted prices must decline. Computing the X factor, particularly in the transmission sector of the industry will require considerable study in the near term. The major issue will be in estimating congestion, losses and ancillary service costs and determining how the production function for transmission service can be shaped by the ITC’s management to increase operational efficiency (i.e., improve productivity). A variety of other issues also are relevant to the determination of the X factor including instances where only a subset of the regulated firm’s services are subject to PCR, where the prices set by the regulated firm affect the rate of output price inflation (i.e., affect the price escalation index I), where the firm’s industry is subject to structural shifts (such as are being experienced today in the restructuring of the wholesale markets and transmission sector) and situations where the firm is subject to increasing competitive forces (e.g., where technological innovations increase the competitiveness of local resources, such as distributed generation that lower the demand for long-distance transmission of electricity). These issues need to be addressed on a case-by-case basis in the course of developing a PCR for a particular ITC.

Additional Provisions and Issues

The price cap index is probably the most important feature of PCR. Other important provisions, however, have been recognized as contributors to the success of price cap plans. An important group of provisions concerns the application of the price cap index. Application issues include consideration of any services subject to price escalation restrictions, price discounting privileges and other pricing variables, protections for customer subgroups, termination of price escalation privileges, and the form of the actual price index. Other provisions that could be considered for ITC price cap plans that have been incorporated in price cap plans for telecommunications companies include more overt promotion of benefits sharing between the company and its customers, and promote demand-side resource management and improvements in service quality. Again, these issues have been addressed in other industries and contexts in which PCR has been applied, and can be addressed directly in the course of developing PCR for ITCs as well.

45 Studies to identify areas of possible productivity gains will be linked to the functionality that the Commission has allowed the firm. When the ITC is granted greater functionality, there will be increased scope for cost reductions and productivity improvements, particularly when tradeoffs can be made between short-term operational decisions and long-term investment decisions. Given the more limited currently approved functionality, these studies could take a few years to establish the baseline costs and practices that could be subject to the price cap X factor.

Efficient Price Caps

Price regulation of natural monopolies always has wrestled with the issue of efficient pricing when the object is to ensure the firm’s viability (i.e., it recovers its total costs including a normal return on capital). But large fixed costs can drive a wedge between marginal costs and average costs, which means neither marginal cost pricing nor average cost pricing will be efficient. Prices based on marginal costs (i.e., based on a competitive pricing model) will not recover total costs because marginal costs are significantly below average costs or any regulatory surrogate for market-clearing prices. Prices based on average costs hide the impacts of incremental use and create cross subsidies among consumers, leading to inefficient consumption. Therefore, the two-part tariff (with variable and fixed cost components) has been widely adopted as a more efficient way to price monopolistic network services.\(^{47}\)

The two-part tariff under a price cap would start with the cap described above and separate costs into variable price and fixed price components. The variable price component would be structured to recover the estimated costs of the variable aspects of the total cost basket. For example, if an ITC were functioning as an ITP and responsible for congestion costs, losses and ancillary services, those costs could be included in the variable component, along with administrative and general (A&G) and operations and maintenance (O&M). The fixed cost components would be calibrated to recover the fixed costs of the system. These could include all of the existing fixed costs as well as estimates for future expansion. Thus, in the short run, the ITC would strive to reduce the variable costs as much as possible. Any increase in those costs would drive the ITC to seek to make take an action or make a capital investment that would reduce the transmission usage costs. For example, if congestion costs were mounting, the firm could induce a generator to locate on the high side of the constraint, or induce a load-serving entity (LSE) to undertake a demand response program. Alternatively, the ITC could decide to build transmission, again seeking the lowest cost option, which could be a solicitation for expansion options or a self-build option. Either way, the solution would entail incremental costs that were less than the incremental benefits (i.e., the reduction in the congestion costs, losses and ancillary service costs) and one that would be the lowest cost overall, in order to maximize the ITC's internal rate of return (and any sharing with customers).

An efficient price cap for an ITC would be based on a two-part tariff involving variable price and fixed price components corresponding to the ITC’s variable costs and fixed costs.\(^{48}\) The average price for transmission service in a pricing cycle (e.g., a five-year period) would be a weighted combination of a variable price representing the price of transmission usage, (a transmission usage fee) and a fixed price representing the price for transmission access, (a transmission access fee). For simplicity, assume the weight on the transmission usage fee is the quantity of electricity transmitted (i.e., the quantity of transportation services sold) during a pricing period and the weight on the transmission

\(^{47}\) However, even simple two-part tariffs can be improved upon by using discriminatory pricing (e.g., self-selective tariffs such as those used in applications of real-time pricing programs).

access fee is the number of customers who contract for access to the grid. The average price can be written as:

\[ P_t = V_t \times Q_t + F_t \times N_t, \]

where \( V_t \) is the variable price in the current period (e.g., the price for transmission use, consisting of the incremental congestion costs, losses and ancillary services), \( F_t \) is a fixed fee in the current period (e.g., a transmission access fee for recovery of the fixed costs of transmission infrastructure), and the weights are \( Q_t \), which is the quantity of electricity transmitted in the current period, and \( N_t \), which is the number of customers in the current period.

The initial (first-year) value of the price cap constraint would be set according to a weighted price with weights on the transmission usage price and the transmission access price based, for example, on projected (baseline) values for quantity and number of customers. Or, it could be the values of those variables determined in a previous period or some other values agreed upon by the regulator. In succeeding years of the pricing cycle, the price cap would be determined by the weighted combination of the transmission usage fee and the transmission access fee, with the weighted price adjusted for input price escalation and for productivity gains.

The price cap constraint means that the average price in the current period cannot exceed the average price in the previous period adjusted upward for increases in input costs (i.e., the price escalation factor \( I \)) and adjusted downward for decreases in costs due to productivity improvements (i.e., adjusted downward by the productivity offset \( X \)). In general, the formula relationship can be written as:

\[ P_t = (V_t \times Q_t + F_t \times N_t) \leq (V_{t-1} \times Q^W + F_{t-1} \times N^W) \times (1 + I - X), \]

where the subscript \( t-1 \) denotes the previous period, \( Q^W \) and \( N^W \) are chosen values of \( Q \) and \( N \) that act as weights to set the upper limit on the average price in the current period.

A two-part tariff for transmission service separates recovery of fixed (investment) costs from recovery of variable costs associated with use of the transmission system and is more efficient than a simpler one-part tariff (i.e., a tariff that attempts to recover both fixed and variable costs through an “all-in-one” price). Consequently, price caps defined on two-part tariffs lead to more efficient pricing and investments.

The benefit of a price cap based on the two-part tariff is that it ties the recovery of fixed costs through the transmission access fee to the transmission usage price. This presents the ITC with an explicit tradeoff between revenue from transmission access fees (i.e., fixed cost recovery) and revenue from transmission usage fees (i.e., the spot pricing of electricity for congestion relief, losses, and related ancillary services), when increases in variable fees

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49 The average price, \( P_t \), can be written generally as \( P_t = V_t \times Q_t + F_t \times N_t \) where \( V_t \) is variable price in the current period (e.g., the price for transmission use, consisting of the incremental costs of congestion, losses and ancillary services), \( F_t \) is a fixed fee (e.g., a transmission access fee for recovery of the fixed costs of transmission infrastructure) in the current period, and the weights are \( Q_t \), which is the quantity of electricity transmitted in the current period, and \( N_t \), which is the number of customers in the current period.

50 The price-cap constraint can be rewritten as \( (V_t \times Q_t + F_t \times N_t) \leq (V_{t-1} \times Q^W + F_{t-1} \times N^W) \times (1 + I - X) \) where the subscript \( t-1 \) denotes the previous period, \( Q^W \) and \( N^W \) are chosen values of \( Q \) and \( N \) that act as weights to set the upper limit on the average price in the current period.

51 See Vogelsang, op cit.
push the Pt above the price cap constraint, fixed fees must be adjusted downward, placing fixed cost recovery at risk.  

**PCR within SMD**

For the ITC operating as an ITP within an SMD framework and LMP-based spot market, the transmission usage costs (i.e., congestion cost, ancillary services and losses) are related to or depend upon the energy spot price. Thus, the transmission usage fee in the price cap formula can be composed of prices for the various services that the ITC could provide, all of which will be connected in some way to the spot price for electricity. For example, an increase in congestion costs, ancillary service costs or losses will increase the usage fee, V, in the current period. If the increase pushes the average price above the price cap constraint, the fixed fee must be adjusted downward, placing the recovery of fixed costs at risk. The ITC administering an LMP-based spot market will be concerned about managing transmission congestion, ancillary services and losses so that the price cap constraint does not become a binding constraint on its recovery of transmission infrastructure costs.

A price cap plan for a fully functional ITC covers services associated with spot market activity (real time operations and possibly day ahead scheduling) as well as long-term planning and expansion. The ITC thus will want to focus on increasing the efficiency of the short-term market and the long-term market. The lowest prices for energy-based services that the ITC would be providing in real time will be achieved through a competitive spot market, so the ITC will want to do whatever it can to facilitate increases in the competitiveness of the spot market (through maximizing the transfer capacity of the existing grid, through the design of market rules or in terms of its operation of the system). The ITC would be in a position to know whether it can take steps to reduce the transmission usage costs in the day-ahead market given the offers and bids of supply and loads. In addition, the ITC could take steps in managing the real-time to reduce usage costs (e.g., by increasing line ratings; redispetching the system to address situations that could enable generators to exercise market power). These actions would be transparent to the market and hence to the market monitor and the regulator.

### 2.5 Alternatives to Price Cap Regulation

There are many alternatives to a pure price cap regime. Incentive regulation has been around since the 19th century in various forms. Three alternatives merit discussion that could be applied to ITCs to motivate both non-discriminatory behavior and improved efficiency, and therefore, fulfill the FERC’s objectives in promoting SMD: benchmarking, performance targeting, and earnings sharing mechanisms (ESMs). These are discussed briefly. This section also discusses COSR as a special case of PCR.

52 Alternatively, separate price caps could be constructed: one on variable charges and one on access charges, but the incentive effects would be the same. Separate price caps would be administratively more cumbersome and likely to invite greater intervention and micromanagement of the ITC by the regulator, which is antithetical to the adoption of PCR in the first place.

53 The size of the adjustment will be determined at the close of the pricing period, since the actual transmission usage costs are established in real time. Then adjustment needs to be made to transmission access fees for the next pricing period.

54 For a good historical review of PBR, see M. R. Schmidt, op.cit., Chapter 2.
**Benchmarking**

Benchmarking provides rewards to the ITC that are conditional upon performance in designated services relative to an industry standard. The drawback to this for ITCs is that this segment of the industry is still in its nascent stages and there may not be easily identifiable industry standards for defined performance indicators. The exception may be in the area of reliability where NERC and the industry have well-developed “best practices” and performance standards. If industry standards were to be established, they would focus on O&M costs, A&G costs, outages, congestion, and perhaps also on some metrics for transaction scheduling effectiveness, ancillary service market administration and so forth.\(^55\)

The reward system could be based on predetermined adjustments to earnings, given actual performance with respect to benchmarks based either on industry standards or on individual company indices. For example, a symmetric reward system, consisting of changes to the rate of return on equity (ROE), would decrease ROE by 100 basis points for a 10 percent increase in outages during a year or a similar percentage increase in some other measure of service quality (e.g., voltage drops), increase ROE by 100 basis points for a 10 percent decrease in outages, with larger or smaller changes based on concomitant changes in transmission outages.

**Performance Targeting**

Performance targeting can also provide a kind of benchmark against which the ITC’s actions can be measured and ultimately rewarded. Performance measures also provide some assurance that the incentive scheme will not be used to increase profits at the expense of reliable service or customer service. For example, performance targets (or indicators) can be established for transaction costs, transaction scheduling efficiency, reliability, congestion management and costs, interconnection facilitation and maintenance. The performance indicators and the weights attached to each indicator to determine overall performance that will be tied to a reward structure similar to that described for benchmarking must be clearly established beforehand. The greatest challenge to performance targeting is to establish a set of targets that reflect those functions that are important to both the regulator and to customers and assign a set of weights that reflect the relative value customers place on the performance of the functions.

**Earnings Sharing**

Earnings sharing mechanisms are based on common sense economics that says an ITC’s best incentive to pursue productivity enhancing investments or to take actions to improve the efficiency of real-time operations and spot markets would be to allow the ITC to retain 100 percent of the benefits of those investments and actions. Anything less

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\(^{55}\) For example, benchmarking was applied to the Chilean electricity distribution industry beginning in the early 1980s. Price cap regulation was introduced in 1989 as an improvement to the problems of yardstick regulation. Empirical analysis of the experience suggests that price cap regulation has resulted in lower costs (i.e., the ratio of reported costs to revenues has fallen). See R. Di Tella and A. Dyck, “Cost Reductions, Cost Padding and Stock Market Prices: the Chilean Experience With Price Cap Regulation” Harvard University, August 19, 2002.
than 100 percent may result in the ITC foregoing some portion of what would otherwise be beneficial investment or actions. However, earnings sharing can be used as a tool to achieve a variety of different goals. Earnings sharing can be viewed as a means to capture cost reductions for customers. In combination with a price cap program, earnings sharing can also be a safety net that protects customers from price increases if the escalator in the price cap proves too generous or the starting point of the price cap is too high. The challenging task for regulators and ITCs is drawing an appropriate balance between following economic logic and achieving other goals. Earnings sharing mechanisms can be symmetric (earnings above the target are shared with consumers through rate reductions, earnings below the target result in rate increases), or asymmetric (sharing is not equal in both directions; the direction typically favors customers).

Because sharing mechanisms tend to blunt the utility’s incentive to cut costs, the prime motivation for considering PBR, if a sharing mechanism is to be used, it should be designed to apply only when earnings fall outside a very wide band, (e.g., no sharing if earnings stay within plus 200 and minus 300 basis points of a target). In this way, the sharing mechanism becomes a kind of insurance policy to guard against large and unforeseen circumstances. This is similar to a price cap with ‘headroom’ to account for the variance in the forecast of transmission usage costs (e.g., congestion costs).

**Cost of Service Regulation (COSR)**

In practice, COSR can be viewed as a special case of price-cap regulation. For example, if the ITC were operating under COSR, the transmission access fees and prices for any other services the ITC renders would be set through a rate case and typically fixed for a period of three years. The object of the rate case is to set prices so that the ITC recovers no more than its future cost of service as projected by adjustments to recent past actual costs. Once prices are set, the ITC would be allowed to keep any additional profits that it earns by reducing costs, at least between rate cases. Thus, between rate cases, COSR operates in a way similar to PCR, albeit with the productivity factor X set equal to the price escalation factor I.

However, the similarities between PCR and COSR end there. The incentives provided by COSR are much weaker than PCR because, in theory, the ITC would anticipate that the regulator at the next rate case would capture any cost savings. This illustrates the fundamental regulatory trade-off: more frequent rate cases allow closer tracking of the cost of service, but they dampen the regulated firm’s incentive to cut costs.

Moreover, the dynamics of COSR requires the regulator to be deeply concerned about the ITC’s costs, since the revenue cap is based on cost projections. The nature of COSR creates a principal-agent problem for the regulator because the regulated firm is motivated to misreport its costs and earnings in order to protect a share of the cost savings it has achieved during the revenue cycle. Placed at an informational disadvantage, the regulator is motivated to micromanage the ITC, which automatically dampens the incentives the ITC has to innovate, lower costs and improve service quality.

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56 There is empirical evidence to support this view of the regulated firm’s strategic thinking. In Chile for example, wires utilities consistently experienced cost increases around the time of the regulatory reviews of the incentive program.
While PCR does not offer a perfect solution to the problems with COSR, in theory at least, the application of PCR vastly reduces the problems of informational asymmetry and the consequent strategic gaming that occurs under COSR.

2.6 Hybrid PBR Programs

Broadly based PBR in the form of rate freezes, earnings sharing and price caps have become more common in the U.S. energy industry in recent years, among retail distribution utilities in particular. Their growing popularity stems from the recognition that targeted incentive programs may encourage the utility to focus excessively on the target and underperform on other important performance dimensions. In a recent survey, Sappington et al found that of the 28 electric distribution utilities that operate under a PBR, 13 operate under some form of rate freeze (or rate case moratorium) and 14 operate under a variant of a price cap. Of the 28 active PBR programs, 21 contain an earnings sharing provision or simple rate of return ‘deadbands.’

Another reason hybrid PBR programs are used rather than pure price cap plans is that regulators fear that they will leave too much rent (i.e., profit) on the table with PCR. In addition, hybrid programs provide a means to share the benefits of cost reductions between the utility and its customers during periods of transition to more competitive markets. This was the case in the early years of restructuring of the telecommunications industry. The shift away from COSR was done in stages, with rate case moratoria, price freezes and earning sharing mechanisms applied at first and for some time before the widespread adoption of price cap plans in the mid 1990s. The experience in the telecommunications industry should provide some excellent support for a more rapid deployment of price cap plans for ITCs.

3. The Elements of a Price Cap for an ITC

This section explores how developing a price cap for an ITC could be applied to a range of incremental models of ITC functionality, covering the full functionality assumed for the ITP in the SMD NOPR (Table 1) down to the functionality established for several ITCs in recent FERC orders (e.g., the TRANSLink order and the order on TransConnect’s innovative rate proposal). The benefits that a price cap program can provide are maximized when the ITC is made fully functional (i.e., operates as an ITP), because the ITC can then internalize grid externalities and optimize over short-run operational costs and long-term expansion and alternative solution enhancement opportunities. Nevertheless, incremental variations are included because that is the realistic approach and because that is where all of the incentive tensions are most visible. Limits on the ITC’s functionality will reduce the size of the welfare benefits, but they reflect the current state of industry restructuring at this time with RTOs dominated by ISOs functioning as ITPs. The section will also examine COSR as the obvious alternative to PBR so it is clear that the benefits of a price cap program are not entirely sacrificed under continuation of COSR.

58 Refer to other citations to the literature in this report.
The design of a price cap plan for an ITC starts with the recognition that non-discrimination and efficient operations and investment are interrelated. When an ITC’s profitability, including the return of and on investment in infrastructure, is tied to the efficiency with which it provides day-ahead scheduling, dispatches real-time markets for spot energy and ancillary services (as POLR) and manages congestion and emergency situations, the ITC will concentrate on ways to provide efficient service and solutions to grid problems (e.g., congestion). A symmetrical plan that rewards the ITC for good performance (short-run costs and least-cost grid expansion) and penalizes the ITC for poor performance results in non-discriminatory management of the grid that finds optimal solutions to grid problems from the full range of generation, demand-side resources and transmission options. When the ITC is rewarded with a share of the value of benefits derived from superior operations and long-term grid management, it will choose to maximize that value, which places all options on an equal footing based on a cost-benefit calculus.

The obvious challenge with PCR based on a two-part tariff lies in setting the price cap so that the ITC stays in business, is motivated to make efficient investments and efficiency improvements in grid operations but does not make profits that are unconscionably high or that result in prices that make customers worse off than they were under COSR. The challenge is to set the price cap as low as possible while allowing the ITC at least a normal rate of return. If the cap can be set low enough, the incentive will be a success.

3.1 Price Cap for an ITC with ITP Functionality

The introduction of a competitive bid-based spot market with LMPs does not create any insurmountable difficulties for the design of a price cap plan. As an energy cost measuring device, LMP makes the congestion costs, ancillary services, losses and the costs of other energy-based elements of transmission service transparent to the customers and the regulators as well as to the ITC, as they should be for an efficient market. Consequently, the ITC’s performance is also transparent. Thus, LMP actually facilitates developing a PCR. Transparency is the key difference between the U.K. style price cap and a price cap plan for an ITC under LMP in the United States. Spot market price volatility and the independence of market participants make forecasting more difficult for the ITC than the forecasting job that faced the vertically integrated utilities. But this means that the ITC can be subjected to financial risk under a price cap plan that

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59 Graves and Stoft critiqued three PBR schemes, two of which involved price capping some measure of ITC performance. One scheme involved a price cap tied to a measure of throughput consisting of flows. As they note, it is difficult to define a measure of throughput that works. Another commonly suggested incentive scheme involves rewarding the ITC on the basis of congestion costs alone. But G&S point out the well-recognized problem with this plan. If it rewards the ITC with congestion rents (i.e., based on congestion revenue rights, for example) the ITC will have incentives to make a bad situation worse. In addition, the ITC may choose to reduce congestion by over-building (i.e., reducing congestion to zero) or restrict access to congested interfaces so that congestion appears to be zero. Either outcome is an inefficient use of the system. The third incentive scheme entailed a price cap for an ITC with the functionality of an ITP. They conclude that this scheme offers “ideal” incentives to ensure that the sizing and timing of network expansion is efficient. F. Graves and S. Stoft, op. cit.
60 Spot prices and consumption and locational decisions of market participants are endogenously determined, which complicates the optimization problem for the ITC.
more closely resembles that faced by a competitive firm. Theoretical work and empirical evidence have demonstrated that the regulated firm under PCR increases its efficiency when it operates in a more competitive environment.\footnote{See Bernstein and Sappington, op. cit.}

When the ITC’s functionality is limited — it does not run a bid-based spot market, manage congestion or operate as POLR for all reserve services — the activities that the ITC can control are limited and therefore so too are the incentives to reward the ITC for good performance, since less of the system is under the control of and subject to the discretion of the ITC. Therefore, in this section, assume that the ITC has full functionality of an ITP under FERC’s SMD.\footnote{The ITC has responsibility for at least 13 functions outlined in the SMD NOPR, refer to Table 1 in the Appendix. These functions are refined from the four minimum characteristics and eight functions outlined in Order 2000. The four minimum characteristics are: independence, appropriate geographic scope and regional configuration, operational authority for all transmission facilities under the RTO’s control, and exclusive short-term reliability authority. The ITP/RTO applicant must also satisfy the following eight functions: 1) transmission tariff development and administration that will promote efficient use and expansion of transmission and generation facilities, 2) develop congestion management procedures, 3) develop and implement load flow and parallel path procedures, 4) serve as the provider of last resort for all ancillary services, 5) operate a single OASIS (Open-Access Same-Time Information System) for all transmission under its control, and be responsible for independently calculating Total Transmission Capacity (TTC) and Available Transmission Capacity (ATC), 6) monitor markets to measure market power and market design flaws and propose remedies, 7) plan and coordinate necessary transmission upgrades and additions, including coordinating its efforts with state regulators, and 8) develop mechanisms to coordinate its activities with other regions, whether or not an RTO exists in those regions, especially concerning reliability and market interfaces.}

A price cap for an ITC with less than full functionality is considered in Section 3.2.

Assume that pricing for transmission use is based on the differences in LMPs at the points of delivery (POD) and points of receipt (POR).\footnote{It is assumed that a significant proportion, 80 to 90 percent, of the wholesale volumes traded are exchanged under bilateral contract, so that the spot market is a residual, balancing market, as has been typical in recent experience in the markets administered by the New York ISO, PJM and New England ISO. The California market design required all purchases to be made through the spot market, which meant that when prices started to rise, virtually no customer had a financial hedge in the form of a bilateral contract.}

A revenue requirement is established for the ITC’s portion of the transmission network.\footnote{It is assumed that the ITC has consolidated transmission assets covering a large regional market serving enough generation and load to have a competitive spot market and liquid forward markets for energy and capacity.} Revenue recovery is based on a two-part tariff composed of transmission usage charges (based on LMPs) and transmission access charges. The price cap on usage and access prices in effect limits the revenue that can be recovered in a pricing period (e.g., a year). If the transmission usage charges (i.e., prices) driven by LMPs (albeit subject to the operational decisions of the ITC) rise above a target level, a portion of the revenue from transmission access charges will be placed at risk. To preserve the revenue from transmission access charges (so access prices do not have to be lowered), the ITC will have to take actions to keep the transmission usage charges at or below the target level.

Obviously, the great challenge is the accurate prediction of the level of congestion and losses and the associated LMPs to determine the target revenue level. Quantifying the
total cost of congestion is difficult without several years’ experience with a large, centralized regional market such as those administered by the ISOs in PJM, New York, California and that which will be administered by MISO. This militates in favor of moving incrementally to adopt the full PCR. Although, with significant consolidation of transmission assets under one ITC roof, an ITC could be administering regional markets sufficiently large to compute reasonable estimates of congestion costs. Even then quantification can be difficult. Congestion costs could be obtained if the ITC could compute an unconstrained dispatch and associated costs and then compare it to the actual dispatch and its costs. While computation of congestion costs is not as simple as subtracting unconstrained costs from constrained costs, it is doable, given a complete and accurate set of bids and offers. Certainly, in markets where electricity flows have adapted to the market environment rather than on the pre-LMP market models, it should be easier to estimate on the basis of experience as well as projected prices, since the congestion and losses patterns have stabilized to some extent.

Electricity demands (i.e., loads) and generation can be distinguished spatially and temporally, and would need to be in the case of spot markets dispatched on the basis of LMPs. The ITC has two sources of costs associated with serving those spatially, temporally separated loads and generators—costs that establish the revenue requirement: transmission usage costs and transmission infrastructure costs. Therefore, revenue will be recovered through two types of charges in the case of two-part tariff: transmission usage charges and transmission access charges. In theory, with no congestion or losses, there would be no difference between nodal prices and the revenue collected from transmission usage charges would be zero; with congestion and losses, revenue from transmission usage charges would be positive. The ITC must obtain the rest of the revenue requirement through transmission access charges.

Under PCR, there would be an overall price cap on the transmission usage charges and access charges (or price cap based on a weighted average of these two sets of charges). The actual transmission usage charges would be determined by the LMPs that result from the ITC’s scheduling and dispatch decisions given bids and offers (received in a day-ahead market and as actually dispatched in real time, for example). If the transmission usage charges increase during a pricing period above a target level, the ITC would have to adjust the transmission access charges downward ex post, subject to the overall price cap and the level of transmission usage charges. This makes the ITC a residual claimant (i.e., it keeps the revenue that remains after transmission usage costs are compensated).66

65 I am indebted to Ross Hemphill of Laurits R. Christensen Associates for an elaboration of the mathematical representation of the ITC’s optimization problem under a price cap plan. Let \( y \) represent loads and \( g \) represent supply. Let \( p \) represent the nodal price paid by loads and \( z \) represent the nodal prices paid to supply. The transmission usage charges would generate revenue over a year

\[
R_{TUC} = \sum_{i,t} P_{it} \cdot Y_{it} - \sum_{j,t} Z_{jt} \cdot G_{jt} .
\]

If \( R_{TOT} \) represents the total annual revenue from transmission usage charges and transmission access charges, then \( R_{TAC} \), the revenue from transmission access charges will be equal to \( R_{TOT} \) minus \( R_{TUC} \).

66 Assume that both transmission usage fees and transmission access fees are limited by a price cap index. In theory, the transmission usage fees are determined by efficient dispatch, while the ITC determines the values of the transmission access fees, subject to the overall price cap constraint. Assuming that there are
The ITC will combine inputs to the production of transmission service (e.g., transmission facilities, ancillary services and maintenance) given the input prices and the physical, technical and regulatory limits that define the production possibilities set. Then the ITC will seek to maximize the profits it can earn subject to the price cap constraint.\(^{67}\) Thus, this proves to be a conventional price cap problem for a firm that purchases the intermediate inputs, combines them with internal inputs, and provides outputs, and where the prices of the outputs and intermediate inputs (i.e., energy-based inputs in this case, for example, ancillary services and generation dispatched around congested paths) are subject to the price cap constraint. In the short run, incremental increases in the transmission inputs would be undertaken where the marginal cost of the input is less than the incremental increase in its value added.\(^{68}\)

The concept behind an ideal price cap plan is to put the ITC at risk for the costs of the intermediate inputs, as well as the internal inputs (i.e., the transmission infrastructure costs). The intermediate inputs are the elements of transmission service provision, the energy purchased to provide regulation and contingency reserves for example. The costs of the intermediate inputs are related to the prices for the outputs and the intermediate inputs are determined by the ITC’s real-time dispatch, nevertheless those prices are capped in the sense that the ITC’s total revenue in a pricing period (e.g., a year) cannot exceed some predetermined level of revenue adjusted for input price inflation and increased productivity. Thus, when the actual revenue from transmission usage charges pushes total revenue above the cap, it will require the ITC to adjust transmission access revenue down, which will mean lowering transmission access fees for loads, generators or both.

As a result of the connection between recovery of transmission access revenue and transmission usage fees, the ITC will be motivated to take steps to minimize LMP differences, in other words, to reduce congestion costs, ancillary service costs and losses. Such a price cap plan provides nearly ideal incentives, in the sense of encouraging efficient and timely improvements to the grid and unbiased and efficient administration of market and real-time grid operations.

One form of optimal price cap scheme would allow the ITC to collect revenues based on a usage fee and an access fee, with enough room built into the cap to cover the likelihood that transmission usage costs due to congestion, ancillary services and losses

\[
\pi = \sum_{i,t} \left[ p_{i,t}^a \cdot y_{i,t}^0 - \sum_{j,t} z_{j,t}^a \cdot g_{j,t}^0 \right] - w \sum_k k_k, \quad \text{where } \pi \text{ represents profit that is subject to the production possibilities set } F(y, g, k),
\]

no additional limits on the pricing of the transmission access charges, the ITC’s price cap constraint can be represented as:

\[
\sum_{i,t} \left[ p_{i,t}^a \cdot y_{i,t}^0 \right] - \sum_{j,t} \left[ z_{j,t}^a \cdot g_{j,t}^0 \right] \leq R_0^0, \quad \text{where } y^0, g^0 \text{ represent base period levels of electricity demand and generation quantities and } R_0^0 \text{ represents a revenue level determined by the price cap index (discussed in Section 2.4).}
\]

\(^{67}\) Assume the transmission inputs are represented by k, and the transmission inputs have unit price w. The transmission production possibility set (i.e., the full range of options for providing transmission service) is represented by F(y, g, k). Then, the ITC would seek to maximize the profit function:

\[
\pi = \sum_{i,t} \left[ p_{i,t}^a \cdot y_{i,t}^0 \right] - \sum_{j,t} \left[ z_{j,t}^a \cdot g_{j,t}^0 \right] - w \sum_k k_k, \quad \text{where } \pi \text{ represents profit that is subject to the production possibilities set } F(y, g, k) \text{ and the price cap constraint.}
\]

\(^{68}\) In general, the term value added is defined to be total revenue less the cost of intermediate inputs. In this context, this value equals the net revenue generated by transmission usage fees and transmission access fees.
will be higher than projected (given actual usage costs will only become known ex post as determined through the real time spot market). Either the price cap is set so that the usage fee component covers the expected transmission usage costs with a fixed component that acts as a surcharge on usage, or the access fee is set high enough to cover the expected (positive) variation in transmission usage costs. Some arbitrariness may be introduced into setting the cap because it has to be set high enough to ensure that the ITC will not go out of business if the actual transmission usage costs are unexpectedly high.

However, the incentive for the ITC is that it would be permitted to keep a portion of any reduction in transmission usage costs that it secures through improvements in grid operations or grid investments. A variation on this involves the revenue from the sale of CRRs. Again, the ITC would be permitted to keep any difference between the CRR revenue and the actual transmission usage costs (i.e., congestion costs) that it secures through improvements in grid efficiency.

An alternative price cap plan places the revenue from the transmission access charges at even greater risk if the cap is much less generous and thereby requires the ITC to adjust transmission access fees downward when the transmission usage costs increase above the capped amount. In theory, this plan would provide strong motivation for the ITC to increase market and grid efficiency to prevent reducing recovery of fixed costs or at least reducing the rate of return on capital. However, it does not contain the positive incentive of the previous scheme in which the ITC is rewarded with a share of the benefits of reduced transmission usage costs.

In general, the cap on the revenue from transmission access fees will be set higher than the revenue requirement for recovery of fixed costs because it must recover the cost of the grid plus a appropriate variance in transmission usage costs from the forecast amount. The recovery of revenue through transmission access fees is completely borne by the ITC. Assume that the transmission access fees must recover $1 billion/year to cover fixed costs alone and the transmission usage fees are expected to recover $1 billion/year plus or minus $400M/year due to the uncertainty about the forecast of transmission usage costs. In this case the price cap on transmission access fees could be set at $1.4 billion/year. This offers the ITC the opportunity to earn an expected profit of $400 million/year (over and above its normal rate of return on capital), and a guarantee of positive profits. The ITC cannot earn more than $400 million/year because the portion of the revenue requirement covering transmission usage costs represents a straight pass through of those costs to customers. Moreover, if actual transmission usage costs turn out to be $600 million, the cap will require transmission access fees to be adjusted downward. The question is how to set the cap to cover expected costs that does not leave the ITC with unreasonably high profits or financially devastated by unexpectedly high transmission usage costs. Obviously, the key will be in setting the initial cap and the quality of the forecast of transmission usage costs. More work must be done in this area.

One method of reducing the expected excess profit, often referred to as the ITC’s rent, is to observe the magnitude of this excess and reduce it over time. But this process distorts the ideal incentive for the ITC to make investments over an appropriate period.

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69 This entails additional incentive issues that require more research.
70 The additional earnings potential lies between $0 and $400 million/year.
For example, if the cap is adjusted so effectively that the ITC is allowed some small profit at all times, the incentive will have been destroyed. The ITC will know that no matter how it performs it will make the same excess profit. The general result is that there remains an unavailable tradeoff between the ITC’s rent and the power of the incentive. To produce a high-powered (i.e., ideal) incentive and be sure of keeping the ITC in business, the regulator is forced to leave some share of the increase in surplus for the ITC. By reducing the effectiveness of the incentive, it is possible to re-capture some of the ITC’s rents and to move the ITC closer to an optimal (i.e., appropriate risk-adjusted) level of profit. Obviously, regulation cannot duplicate the perfect incentive and the zero rent condition that can be achieved under perfect competition.

3.2 Price Cap for an ITC with Less Functionality

Price caps can be designed for ITCs with less functionality than an ITP under SMD. And there will be many situations in which the ITC plays a subordinate role to the ITP or operates in coordination with an ITP to serve a large subregion, especially during a transition from the traditional industry and market structure to SMD. In some instances the ITC may not be responsible for running a real-time spot market, acting as the POLR for ancillary services, or for managing congestion, but will still have responsibility for a subset of functions that determine transmission usage costs. In other cases, the ITC may be the default provider of real-time markets, reserve services and congestion management when the ITP is not in a position to perform such functions (for example, during the transition to the LMP-based market for MISO).

Whatever subset of functions falls to the ITC, that subset can form the basis for a price cap on what the ITC can collect from customers through transmission usage and access fees and to link reward for its performance of those functions to recovery of transmission access fees as described in Section 3.1.

The price cap formula remains the same as for full ITP functionality. The mechanism works in the same way to create incentives for the ITC to improve operational efficiency and to optimize over the short term and the long term. The difference is that the number of functions that would determine the target costs to set the price cap will be smaller.

While the ITC may play a subordinate role to the ITP/RTO, it may still have substantial functional responsibilities. The ITC may be providing a number of services that would permit an effective PCR plan to be developed with properties similar to plans for ITCs with full functionality. For example, an ITC could be the control area operator for consolidated grid assets and be responsible for securing reactive supply, voltage control and regulation from local generators.\(^\text{71}\) It may also be responsible for taking actions to address emergency situations in coordination with the ITP. In this case, it would be possible to develop a price cap that rewards the ITC for the cost reductions that it secures in providing these services. The ITC may also be able to make investments that reduce other transmission usage costs that depend on the functions performed by the ITP.

\(^{71}\) It may also be responsible for real-power loss replacement, dynamic scheduling, system blackstart capability, and network stability services.
The price cap plan could be designed to provide incentives for the ITC to reduce these other costs.

As the example illustrates, reduced functionality automatically limits the steps the ITC can take to affect transmission usage costs. By the same token, it limits what the regulator can hold the ITC accountable for in an attempt to induce the utility to improve the efficiency of the system and markets. For example, when the ITC has full functionality, spot prices and congestion matter greatly because they determine transmission usage costs. The ITC under a price cap will want to run the most efficient real-time market possible to keep those costs down. Consequently, the ITC will also be greatly interested in limiting the market power that can be exercised by suppliers serving load pockets subject to congestion. The regulator will have more difficulty enlisting the aid of the ITC to mitigate market power, if the ITC has nothing at stake in that battle.

One benefit of reduced functionality in the context of PCR might be less volatility in the target forecast for capping transmission access fees, greater ease in forecasting it, and perhaps less business risk, which could make the ITC more competitive in capital markets. The obvious drawback is that the strength of the commercial incentive and risk aspects of the price cap built on full functionality is reduced.

An example of how limited ITC functionality reduces the scope of a price cap is seen in the TransConnect, LLC application. TransConnect proposed a PBR plan composed of three parts that combine several of the approaches described in Section 2. The FERC’s recent order on the incentive plan suggests that the Commission is willing to give serious consideration to PBR for transmission companies, although it has moved very cautiously.\(^\text{72}\)

TransConnect proposed a PBR consisting of three parts:

- a price cap subject to an indexed annual adjustment,
- performance benchmarks, and
- incentives for transmission investment.\(^\text{73}\)

The price cap would lock TransConnect’s average rate in place for a five-year period, subject to Commission-approved annual adjustments. Annual rate adjustments during the five-year period would be geared to a price escalation factor based on O&M costs, proxied by the CPI, and an X factor set arbitrarily to reduce the rate of price cap growth by 0.5 percent per year. Rates would also be adjusted using a cost sharing formula for A&G costs, and for incremental cost increases associated with new investment that can be shown to provide system-wide benefits.

The Commission rejected the proposed indexation of O&M costs, saying that it was premature in light of the lack of operational experience and moreover that there was insufficient evidence to support the O&M expenses for each of the TransConnect


companies and to justify the benchmark figure on the basis of the sum of individual companies’ historical O&M costs.\textsuperscript{74}

Another element of the proposed PBR design was a sharing mechanism for A&G costs. TransConnect argued that A&G cost savings would be difficult to predict and proxy in the early years of operations, so the A&G cost portion of the year-one revenue requirement would be based on traditional base and test year measures. Each subsequent year, the revenue requirement would be adjusted to the prior year’s actual A&G costs, with TransConnect sharing fifty percent of the savings with customers and accepting risk for increases over the base-year level.

The Commission accepted the A&G sharing mechanism but directed TransConnect to exclude from its base year A&G levels “those savings that are the result of consolidation of the operation of the individual transmission companies into TransConnect.”\textsuperscript{75} While there probably are economies of scale and scope associated with consolidation, the extent of these are indeed difficult to estimate initially when a new enterprise is launched through the consolidation of disparate transmission systems. A significant proportion of A&G expenses may be fixed by contract and difficult to reduce over short periods (e.g., the initial five-year pricing period). This is one reason why the A&G portion of the PBR involves an earnings-sharing mechanism rather than a predetermined indexed annual adjustment, as in a pure price cap plan. While an earnings-sharing mechanism does not create incentives that are as strong as those achieved with a pure price cap it does motivate the ITC to find ways to reduce costs and assures the regulator that customers will benefit directly.

Nevertheless, the opportunity for the ITC to benefit from these savings is an economic driver of consolidation. A policy that transfers all economies of consolidation to customers – a 100 percent rent extraction policy – will undermine both the incentives and the real objective: greater long-term efficiency. Indeed, the Commission has sought ways to consolidate the transmission industry to reap economies. For example, the Commission has attempted to encourage RTO participation and further the separation of transmission from generation and marketing to ensure market-neutrality through its proposal to reward utilities with ROE adders for joining RTOs and for transmission asset divestiture and an additional increase in ROE for investment in new facilities.\textsuperscript{76} The Commission’s order on TransConnect and its recent policy create a situation in which the Commission may be giving with one hand as it takes away with the other.

The TransConnect PBR proposal reflects the fact that the ITC was not in a position to assume the functionality of an ITP. Smaller in scope and configuration than the RTO, it would be operating within the RTO West footprint, and RTO West would be the ITP. Therefore, TransConnect’s PBR could not have been constructed around the full set of functional responsibilities, services and, most importantly, the main contributors to transmission usage costs, but instead must focus on the only remaining cost categories—O&M costs and A&G expenses.

\textsuperscript{74} TransConnect LLC, Order at p. 10-11.
\textsuperscript{75} Op. cit., p. 10.
The major shortcoming of the reduced functionality is that the two cost categories in the TransConnect PBR are small in comparison to congestion costs, ancillary service costs and losses, the core of the marginal costs of transmission use. Without those critical cost elements, a price cap loses its strong incentive properties. Even the O&M costs may not be controlled entirely by the ITC if it must obey the ITP’s directions. The positive aspect of TransConnect’s PBR is that, under an assumption of decreasing costs (i.e., scope and scale economies), there will be an incentive to acquire additional transmission assets through consolidation, so long as the average incremental cost of consolidation is below the price cap constraint, and so long as the Commission does not seek to extract all the rent associated with it and provide those to customers. This consolidation may also result in a reduction in the number of control areas, which is another Commission objective. Again, a Commission policy of complete rent extraction for consolidation savings will undercut this beneficial movement.

With TransConnect playing a subordinate role to RTO West, a price cap plan that ties investment in transmission facilities to the main performance measures—congestion, losses and ancillary services -- would be out of the question. The narrow formulation of the five-year price cap did not allow for recovery of incremental investments in facilities that provide system-wide benefits. Consequently, a separate incentive proposal was made for incremental investments that included an increase in the rate of return to account for the risk in the new business environment and faster recovery under a 15-year depreciation schedule. The Commission rejected both features of the investment incentive proposal, allowing instead the opportunity for TransConnect to file for incremental rate treatment on new facilities in the future. But this dampens the incentives for new investment by placing them back in the old COSR world, even though this is really the only option when the price cap plan is limited by the ITC’s functionality.

3.3 Cost of Service Regulation: A Special Case of PCR

Assume that an ITC operates as an ITP under COSR serving a regional wholesale electricity market dispatched on the basis of security constrained economic dispatch using LMPs as in the previous examples involving price cap plans. Under COSR, the ITC’s revenue requirement would be fixed through a rate case and rates would be fixed for a revenue cycle (typically around three years), rather than prices being capped. If the revenue requirement constraint were to be effective, the ITC would have to be at risk for any portion of the transmission usage costs that exceeded test year projections. All transmission usage costs could not be treated as a straight pass through to customers, such as fuel costs have been by way of “fuel adjustment clauses,” as they are by the ITP/RTO/ISO today. If all transmission usage costs were passed through to wholesale customers, the ITC would have no incentive to improve the efficiencies in order to protect its revenue requirement. Thus, some form of positive or negative incentive connected to the improvement in transmission usage costs would have to be built in to the COSR scheme. Achieving this would make COSR similar in many respects to the price cap plans. This could be done, but then it would be simpler to develop a price cap plan.

Presumably, the revenue requirement would be sufficient to maintain the system, but would not provide revenue for network expansion. Network expansion would be accomplished through a regulatory proceeding, where the expansion would be deemed necessary, and the revenue requirement would be adjusted. The fact that the ITC would
not be subject to a rate case for several years, regulatory lag can provide the incentive for the ITC to make some kinds of investments in the grid that would lower transmission usage costs and that would contribute to the ITC’s bottom line.

This raises another problem with use of COSR, namely, that the ITC must seek regulatory approval to build a new line and must initiate a rate case to determine the recovery of the capital costs. This means the ITC needs to file with both state and federal regulators (the states still have siting authority) for a certificate of convenience and necessity, a process that must, under traditional COSR, apply a “used and useful” test to a facilities expansion. But applying a “used and useful” test becomes difficult in the context of LMP-based pricing of congestion. This is because power flow on an uncongested line has no price differential and therefore has no usage cost (congestion charge) and therefore has a price of zero. This also applies to a line that is “useful” but not to full capacity and to one that is overbuilt from a total life cycle standpoint: transmission line economics — resulting from the lumpiness of the asset — may necessitate overbuilding of lines so that long-term costs are optimized.

An alternative approach as suggested by Graves and Stoft, that has some of the spirit of the ideal incentive but leans heavily in the direction of COSR would have the ITC collect its revenue requirement on a per-MW-of-access basis. Thus, the revenue requirement can grow with rate base additions. Rate base additions, in turn, would be found to be “used and useful” based on the present value of avoided transmission usage costs in excess of the associated expansion costs.

This approach would help solve the “used and useful” problem that plagues COSR for ITCs, but it is not necessarily easy. To determine if a line should have been built (will be useful), it is necessary to compute its effect on the present value of transmission usage costs. This is far more difficult than what is required under a price cap plan. In that case, it is only necessary to compute transmission usage costs from actual costs. To implement the alternative approach to COSR, it is necessary to compute transmission usage costs far into the future.

4. The Benefits of ITCs Operating Under Price Caps

This section explores the benefits of price cap regulation of ITCs. It focuses on the effects of a price cap, overlaid on a two-part tariff, on efficient operations and investment. It also discusses the effect of the price cap on securing ITC behavior that is consistent with the desire to achieve Order 2000 independence toward market participants and other transmission owners. This section will also discuss the benefits of a price cap that can be used as a means to smooth out the transition from the traditional world of vertically integrated utilities to the new world of the standard market design.

77 Under efficient pricing of congestion, when the system is not congested the congestion price is zero.
78 This is not a new problem and is simply part of the transmission expansion problem that states have been dealing with for a long time.
79 Graves and Stoft, op. cit.
80 This also will consider the benefit of enhanced management of the ITC, in addition to the regulatory perspective of the benefits of efficient operations and investment that increases consumer welfare.
4.1 Operations, Investment and Management

The benefits of a price cap plan issue from the fact that it ties rewards to ITC performance that encompasses the regulators’ objectives: non-discrimination, more efficient markets and grid operations, and more efficient investment and thus lower costs to consumers. A price cap plan for an ITC acts much like a contract for differences (CFD) in which the parties mutually insure each other against the difference between their contracted price and the market price. The ITC and regulator agree on a contracted price—the price cap—that includes a provision in the transmission access fees for transmission usage costs. The agreement in the price cap plan is the assurance from the regulator that if the ITC keeps transmission usage costs below the target, it can keep the difference between the “contract price” and the “market price.” The ITC assures the regulator that if the actual transmission usage costs exceed the target, the ITC will refund the difference to customers (the collected price will have exceeded the capped price over the time period and the difference between collections and the cap go to customers). The main difference between the CFD and the price cap plan is that a fully functional ITC would be able to take steps to optimize the locational prices to help lower congestion costs, which is precisely what the price cap plan intends to motivate.

Efficient Transmission Expansion

The price cap based on a two-part tariff links operations and investment and should lead to efficient investment decisions. A new line is built when the incremental cost of the line is smaller than the benefits of reduced transmission usage costs and smaller than the incremental cost of any other option to reduce transmission usage costs. If the incremental cost of either a generation or demand-side resource solution to a grid problem were smaller than the incremental cost of a new high voltage line, the ITC, under a price cap plan, would opt for the non-wires solution. The result for the ITC is the same; the solution reduces transmission usage costs and therefore enables the ITC to earn a performance premium. The ITC should not favor a wires solution if by doing so it reduces the portion of the performance “premium” it can earn.

Even though the price cap plan entails a performance “premium” on transmission access fees that can be earned through good performance, it only presents the ITC with the opportunity to earn that premium; the premium is not guaranteed. A risk neutral ITC would take economic actions in an effort to increase the probability that the premium will be retained and to reduce the probability that transmission access fees would be reduced below the level to recover capital and a normal return. This extends to the point that the ITC would seek investment in transmission through a competitive bidding process to achieve lowest cost results or initiate a self-build or demand response program, whichever is calculated to be least costly over the longer term. The ITC may also motivate coalitions of market participants (e.g., other transmission asset owners, generators and/or load serving entities) to make investments in new facilities by sharing a portion of the performance “premium.”

The last point may be one of the most important in light of the Commission’s interest in market-based solutions to transmission infrastructure expansion. A price cap-motivated ITC may be able to obtain the cooperation of many market participants and even find ways to overcome a state’s opposition to system expansions in cases where
there appear to be no benefits to “native load” customers, but a coalition of customers can be persuaded to either fund or be allocated their full share of the costs.

**Market Power Mitigation**

Experience in California and in other regional wholesale markets has demonstrated that both market design flaws and the presence of congestion (and other network-based problems) can create opportunities for generators to exercise their natural instinct to do what they can to raise markets prices above competitive levels, reducing the benefits for consumers of otherwise efficient competitive wholesale markets. Regulators and legislators are greatly concerned about mitigating generator market power. But suppliers fear regulator’s over-reactions to market power will lead to draconian efforts at mitigation that will drive prices to a level that impedes cost recovery and undermines the attractiveness of generation investment. A major portion of the FERC’s response in the SMD NOPR to the need for better market design has concentrated on the creation of market monitors and mechanisms for mitigating the effects of market power in spot markets, including resource adequacy to dampen price spikes.

Price cap plans for ITCs can provide an efficient tool to address market power problems in wholesale markets. Congestion contributes to generators’ ability to exercise market power, and in some cases, generators may be in a position to affect the level of congestion in order to profit from the enhanced market power it affords them. Here is one instance where the ‘Independence qua neutral party” view of the ITP has drawbacks. The non-profit ISO has nothing at stake in combating market power except perhaps pride in performance; no profits are at risk. But the ITC with full functionality will have profits at risk in running the system under the price cap plan. Congestion costs, a major portion of transmission usage costs, will become a primary focus for the ITC. As manager of its system, the ITC will be in a position to take economic actions in real time as well as over the long term that will have the effect of mitigating market power without the use of algorithms that trigger intervention in the spot market price setting process.  

**Efficient Pricing**

The object of restructuring the electric industry has been to increase efficiency in production, delivery, consumption (i.e., productive efficiency) and investment (i.e., allocative efficiency). The introduction of competition in generation was a step in that direction. And so has been the introduction of LMPs to provide price signals to generators and customers regarding the marginal cost of electricity and transmission use. But even if SMD is not in place and an LMP based spot market is a distant vision, an ITC under a price cap plan will be motivated to move toward an efficient pricing structure as a way to increase the probability that it would earn the reward for lowering transmission usage costs.

Since price cap plans can accommodate nearly any rate design, they can enable ITCs to move to pricing structures that are consistent with the FERC’s goal to eliminate rate pancaking. Moreover, they permit pricing structures that minimize inequitable cost

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81 An excellent critique of the market monitoring practices in place in some ISO regions and now being considered for widespread application in the SMD NOPR can be found in L. E. Ruff, ‘Market Power Mitigation: Principles and Practice,” Charles River Associates, November 2002.
shifting and revenue erosion for contributing asset owners, and enable the application of traditional rate design principles of cost causation and revenue accountability.

While the design of efficient pricing structures to recover the costs of transmission infrastructure in the presence of network externalities has always been more art than science, traditional designs using average rates based on rolled-in methods are well recognized to be inefficient. If customers are homogeneous, average prices are fairly simple to apply, but when customers are heterogeneous, average cost pricing of rolled-in costs becomes more complicated and problematic. Consumers as a whole can be made better off if the utility discriminates even a little based on characteristics of customer classes (again, a well known result). Consequently, the designs traditionally used to price transmission have included very little price discrimination, and therefore, fostered cross-subsidies between and within customer classes as the rule rather than the exception. Both license plate and postage stamp rate designs perpetuate this inefficiency and are less efficient for this reason.

Under PCR, ITCs can shift to a more efficient pricing structure that eliminates (or at least reduces) cross-subsidies and sends more efficient (long-term) price signals to customers. For example, pricing structures under price caps can easily accommodate participant funding or customer contribution policies as part of the overall pricing strategy for deep system transmission investments as well as shallow system investments. This can help to send long-term price signals to both generators and load about the opportunity cost of a locational decision. Rolled-in pricing methods can still be used for recovering costs of deep system facilities that provide reliability benefits to all customers, but the allocation of those costs may still be based on more efficient designs that reflect cost causation (such as distance sensitive access charges and related designs).

Price cap plans enable an ITC to better follow three fundamental efficiency principles in rate design:

- price to the least price elastic beneficiary (or put another way, the most price inelastic beneficiary),
- spread the costs across the widest possible base, and
- recover fixed costs through fixed charges, variable costs through variable charges.

An ITC that has consolidated transmission assets of several utilities under one management and into one large control area will be motivated to use pricing strategies to encourage customers to make efficient use of the existing infrastructure without placing the revenue requirement at risk. By applying the three principles within a price cap plan the ITC should be able to do this.

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82 The distinction between deep system components and shallow components will be subject to interpretation, but in general refers to the difference between high-voltage and lower-voltage lines and associated facilities. The FERC uses 138kV to delineate between zonal and highway facilities. All facilities at 138 kV and above will be given high-voltage status and rolled-in rate treatment and all facilities below 138 kV would be given zonal rate treatment. SMD NOPR at P 200.

83 This is also referred to as Ramsey pricing.

84 In other words, use two-part tariffs.
However, regulators will be concerned that the pricing regime not only provides the ITC with a reasonable opportunity to earn recovery of and on its investments but also will want to ensure that customers do not pay monopoly rents, the tariff is fair and does not entail cross subsidies. Thus, in designing a price cap plan, the ITC and the regulator will have to come to an agreement about a price incentive mechanism that satisfies the general objectives for pricing transmission service, which are:

1. Providing transparent and consistent signals to customers.
2. Protecting customers from paying prices that are too high because they include monopoly rents.
3. Providing efficient price signals to electric generators (and loads) about where they should locate.
4. Promoting efficient use of existing generation and transmission assets.
5. Appropriately motivating the ITC to operate its system efficiently.
6. Promoting efficient levels of new transmission investment.
7. Appropriately assigning risks.
8. Giving the ITC an opportunity to earn a reasonable rate of return.

Pricing regulated services always involves a tradeoff among these objectives. For pricing transmission service, the most important tradeoff is how to provide that rates, in sum, cover the ITC’s revenue requirement (i.e., its costs) while still providing the marginal or incremental price signals that encourage economic efficiency in the use of and investment in transmission assets. For example, pricing at marginal cost generally is believed to be consistent with the efficiency objectives 2, 3 and 4 from the above list. But pricing transmission service at marginal cost almost inevitably will under recover the transmission provider’s revenue requirement (i.e., objective 7). So some deviation from the theoretical ideal is required. Preferably this deviation will be implemented in a fashion that minimizes the inefficiencies caused by the deviations.

4.2 Fortifying Market-neutrality

From the Commission’s orders and its SMD NOPR, it becomes clear that the market neutrality of the transmission system operator (otherwise referred to in the industry as ‘independence from market participants’) lies at the heart of the debate over what transmission business models are compatible with competition and a standardized market design.

The SMD is based on the premise that to assure that market outcomes are consistent with reliability and reliability actions do not undermine market efficiency, the system operator must operate a real-time market that simultaneously manages imbalances, congestion, loop flows, interconnection transactions, and all the other interrelated variables that, taken in combination, determine system reliability and the

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efficiency of real-time operations. This makes transmission service monopolistic. When the transmission service is vertically integrated with generation and marketing, there can be conflicts of interest between the generation and marketing functions and the transmission functions performed for all market participants. Hence, separating real-time operations from generation and marketing would seem absolutely necessary to establish the market neutrality of the system operator from market participants and eliminate vertical market power that would restrict competition in otherwise well functioning markets. But is that separation sufficient? How independent of market participants does the transmission system operator have to be to ensure that it provides access and service on a non-discriminatory basis and that it finds optimum solutions to transmission problems that include non-wires as well as wires options?

In Order 2000, FERC stated that “independence” was the “bedrock” for an RTO. Order 2000 required an RTO to meet three conditions for it to be considered independent: it must not have any financial interests in any market participants, its decision-making must not be controlled by any market participant or class of participants, and it must have authority to file changes to the transmission tariff.

Order 2000 left open the possibility that an ITC could meet the definition of “independent” and qualify as an ITP, or at the very least be permitted to administer energy markets, so long as it had no commercial (financial) stake in generation or wholesale and retail sales. With that degree of separation, it could be argued (and was argued by TRANSLink and the Alliance Transco companies and National Grid) that an ITC would have no incentive to unfairly favor some wholesale transactions over others.

The concept of market neutrality (“independence”) boils down to the issue of whether the ITP can be motivated to act in an unbiased manner with respect to short-term grid operations and resource use and decisions about long-term reliability, grid expansion and other options for congestion management. One way to accomplish this is to resort to an ISO-centered ITP that separates operations and the long-term planning process from grid ownership and investment. While the ISO may be a neutral party, separation means that the regulator must find some motive other than profits to ensure that the ISO fulfills the public policy goals (including: reducing transmission usage costs and broadening markets through inter-market coordination and resolution of seams problems\(^86\)); separation by itself does not create incentives.

The ISO-based ITP model short-circuits the profit motive that utility regulators have relied on for the past century to accomplish short-term and long-term public policy goals. Functional separation in the ISO-based ITP model to achieve independence (i.e., market neutrality) severs the fundamental connection between short-term and long-term profitability that can motivate an ITC and that can be harnessed by the regulator to ensure the ITC is market neutral.

Moreover, the ISO-based ITP model relies on third parties motivated by CRRs to engage in expansion and enhancements. For example, vertically integrated utilities naturally have conflicts of interest with transmission expansions that increase local

\(^{86}\) The three Northeastern ISOs do not have a stellar record on coordination and cooperation in resolving inter-regional market problems. This can be attributed in part to the fact that there are no profits at stake and consequently the FERC has no real carrot to hold out to motivate them to cooperate more fully.
competition and lower market-clearing prices. The ISO is not in a position to make decisions involving the economic tradeoffs between wires and non-wires solutions because it does not make investment decisions nor does it have any cost responsibility for any transmission assets. Finally, the independence achieved through the ISO model is based on the concept that the system operator is indifferent to the market outcomes and the implied costs; at least this is the practical result of putting a not-for-profit entity in charge of administering markets and managing congestion in a bid-based, security constrained spot market. There is no reason why the system operator should be indifferent to the market outcomes. In fact, the superior model would make the system operator commercially interested in finding the lowest cost outcome, subject to operational, reliability and security constraints. The appropriate type of independence characteristic needed in the transmission operator is an unbiased regard for all cost-reducing options that ranks and pursues them according to the value of net benefits.

4.3 Bridging the Old World and the New World of SMD

The transition from the old world of bundled transmission provided by vertically integrated utilities to a new world of unbundled, standalone transmission service within a standard wholesale market design will take some time to complete. The period will be shorter in some regions of the country than in others. The Northeast ISOs are already well on their way toward embracing a standard market model in some respects, but many regions of the country were not so well positioned in the mid 1990s as the Northeast power pools to begin that structural conversion.

Price cap regulation can help facilitate the transition from the old structure to standalone ITCs that are consolidating transmission assets of owners with strikingly different corporate structures (i.e., the differences can be as sharp as between VIUs, electric cooperatives and municipalities). The attractive feature of price cap plans is that they can accommodate almost any pricing structure that can be designed, so long as the structure does not lead to a violation of the cap. What is most valuable about PCR, in this regard, is that it permits repricing to take place smoothly during transition periods. That is, the ITC can move from zonal pricing to postage-stamp pricing if it desires without difficulty. An ITC can adopt license plate pricing or develop some hybrid pricing structure such as that proposed by TRANSLink LLC that involves highway pricing and zonal pricing.

87 Some idea of the length of the transition to SMD may be drawn from the general pace of RTO creation and approval. Consider that there are now two FERC-approved RTOs in the country. The first was the Midwest ISO, which has not put any of the mechanisms discussed in the SMD NOPR in place yet and, given its size, is expected to take several years to assemble all the pieces. The second is PJM, which only received FERC's stamp of approval as an RTO in December 2002, but has been operating as an ISO with most of the trappings of an ITP for the past three years.

88 And still the Northeast ISOs are some distance from completing that shift since the transmission business in those regional markets has not achieved a standalone status.

5. Making PBR a Reality

This section outlines steps ITCs and regulators, FERC in particular, can take to move PCR from theory to practice.

Some practical considerations for PCR implementation are to determine:

1. initial prices (i.e., the starting point),
2. the design of “service baskets” and proper allocation of costs to them,
3. the X factor, the annual productivity adjustment, and how to reset it,
4. how frequently to update the price cap,
5. how to re-evaluate the composition of the service baskets,
6. what constitutes an appropriate price escalation factor, and
7. the level of performance premium attached to transmission access fees.

It is good to keep in mind that there is no such thing as perfect PBR or PCR. The best price cap plan can be viewed in such a way as to highlight the negative aspects. A PBR with strong cost-cutting incentives could simultaneously encourage reductions in service quality. We suggest that ITCs and regulators consider the following points:

- Focus on the goals of the PBR and create strong incentives to address them.
- The major structural options are price caps and revenue caps. Both options create similar incentives to reduce transmission usage costs through improvements in operational efficiency and investment.
- Apply a rationality test to avoid getting sidetracked trying to reach perfection and focusing on areas that are unimportant. Compare plans to the existing system of COSR.
- Avoid creating incentives for outcomes that are both undesirable and difficult to measure.
- Avoid the use of sharing mechanisms that tend to blunt the incentive to cut costs, which is a prime motivation for considering PBR. If a sharing mechanism is to be used, it should be come into play when earnings fall outside a very wide band. In this way, the sharing mechanism becomes a kind of insurance policy to guard against large and unforeseen circumstances.
- Whatever price escalation factor (i.e., inflation measure) is chosen, be sure it is not linked to the actual costs of the particular ITC.
- Price escalation and productivity factors demand careful review of historical cost and revenue data. Historical cost data include information about the ITC in question, the industry, and a peer group of firms. The data should be reviewed in the aggregate (total distribution utility costs) and on a disaggregated basis. Give extra weight to recent, rather than older data. Also, consider the future; many innovations that will affect a utility’s costs in the future are already in the planning or implementation stages.
- When considering incorporating additional adjustment factors in the price cap formula, carefully evaluate the implications of adding risk to or removing risk from the ITC. Is it more efficient for the ITC or its customers to bear a particular
risk? Also, how will investment and operational decisions be affected by the shift in risk?

A principal hurdle to the implementation of price cap plans for ITCs are informational. The data necessary to set the input price inflation and productivity adjustment factors in place must be generated by experience of ITCs in grid operations, preferably with the SMD. This experience will therefore not be readily available and may take several years to develop. In addition, setting a price cap with annual adjustments will require establishing a baseline forecast of transmission usage costs, which will involve forecasting congestion, losses and ancillary service costs if an ITC has the full functionality of the ITP. This information and the experience to work with it effectively will only be available with the passage of time.

6. Conclusions

The paper has discussed how an ITC can be regulated under a price cap to perform with the full functionality of an ITP, or with any level of functionality, so that it focuses on the market as a whole and does not unduly discriminate against market participants (generators and demand management resources) and other transmission asset owners. Price cap regulation produces benefits for transmission customers because it aligns asset owners’ incentives with the goals of increasing the efficiency of the market, consumption and investment decisions. It motivates asset owners and their managers to take steps to protect the recovery of the investments by finding economic solutions to grid problems and to meeting reliability standards and growth in the demand for transmission capacity.

Switching from COSR to PBR is not without challenges, however. Designing incentives that achieve all of the goals well requires addressing a number of problems. A well-designed PBR needs to:

- avoid inefficient reductions in O&M costs that lead to reduce system reliability or safety,
- avoid inefficient investment in transmission facilities,
- avoid incenting ITC managers to emphasize particular goals at the expense of others,
- allow the ITC pricing flexibility so as not to reduce the benefits for consumers, and
- avoid undermining the cost-reducing incentives of the PBR by seeking to extract excessive amounts of rent from the ITC.

The benefits of a price cap plan issue from the fact that it ties rewards to ITC performance that encompasses the regulators’ objectives: non-discrimination, more efficient markets and grid operations, and more efficient investment and thus lower costs to consumers. A price cap plan for an ITC acts much like a contract for differences in which the parties mutually insure each other against the difference between their contracted price and the market price. The ITC and regulator agree on a contracted price—the price cap—that includes a provision in the transmission access fees for transmission usage costs. The agreement in the price cap plan is the assurance from the regulator that if the ITC keeps transmission usage costs below the target, it can keep the
difference between the “contract price” and the “market price.” The other half of the agreement involves the assurance from the ITC to the regulator that if the actual transmission usage costs exceed the target, the ITC will refund the difference to customers. The main difference between the CFD and the price cap plan is that a fully functional ITC would be able to take steps to optimize the locational prices to help lower congestion costs, which is precisely what the price cap plan intends to motivate.

Price caps can be designed for ITCs with less functionality than an ITP under SMD. And there will be many situations in which the ITC plays a subordinate role to the ITP or operates parallel to an ITP to serve a large subregion within the ITP footprint, especially during a transition from the traditional industry and market structure to SMD. In some instances the ITC may not be responsible for running a real-time spot market, acting as the POLR for ancillary services, or for managing congestion, but will still have responsibility for a subset of functions that determine transmission usage costs. In other cases, the ITC may be the default provider of real-time markets, reserve services and congestion management when the ITP is not in a position to perform such functions. Whatever subset of functions falls to the ITC can be used to create a cap on what the ITC can collect from customers through transmission usage and access fees and to link reward for its performance of those functions to recovery of transmission access fees.

Applications of PBR and price cap plans should be considered with eyes wide open; they are not a panacea. However, there are strong public interest reasons for examining new regulatory approaches as has been done in other regulated industries as well as abroad. A well-designed price cap plan that replaces COSR’s weaker incentives for investment in improved efficiency and investment in the grid with positive rewards for superior performance is desirable for market participants, transmission companies and regulators. A well-designed price cap plan stands a good chance of motivating desirable behavior. More efficient and creative ITC managers will take actions that benefit both transmission customers and shareholders. Furthermore, price caps can be implemented in all phases of the evolution to SMD. Now is the time to take actions to develop price cap plans for applications in the new industry structure that will ensure the transmission system remains a robust facilitator of competitive wholesale electricity markets.
Appendix:

Table 1 ITP Functions Assigned in the SMD NOPR

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| 1 | Operate all transmission facilities within its jurisdiction and offer nondiscriminatory transmission access through a standardized network access service tariff.  
   |                                                 90                                   |
| 2 | Take responsibility for regional reliability and security and coordination.          |
| 3 | Operate a financially binding, bid-based, day-ahead spot energy market (and a corresponding scheduling market) that determines locational marginal prices (LMPs) and that accommodate bilateral transactions. |
| 4 | Operate a real-time spot energy markets with LMPs.                                  |
| 5 | Manage congestion through use of LMP-based pricing for transmission use, allocation of CRRs, and curtailment rules in the most extreme cases. |
| 6 | Operate day-ahead and real-time ancillary services markets for three services: regulation and frequency response, spinning reserve, and supplemental reserve.  
   |                                                 91                                   |
| 7 | Engage in market monitoring and develop and apply market power mitigation procedures. |
| 8 | File the SMD tariff and changes to it under § 205 (of the federal power act) and make filings on behalf of public utilities under §§ 205 and 206. |
| 9 | Assess long-term resource adequacy needs.                                           |
|10 | Engage in transmission planning and expansion on a regional basis.                  |
|11 | Conduct system impact and facilities studies and simultaneous feasibility studies.   |
|12 | Determine the cost of and responsibility for transmission system upgrades and assumptions underlying associated power flow analyses. |
|13 | Conduct studies relevant to and calculate ATC and TTC only if approved as an ITP.  |

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90 Again in this instance, the size of the physical area encompassed by the ITP has not been made clear. The SMD NOPR appears to leave open the question of whether the ITP’s footprint must be coincident with that of the RTO or can be smaller than the RTO’s footprint. One may conclude from the fact that the SMD NOPR proposes to refine Order 2000 rather than change directions, for an ITP to qualify as an RTO, it must have the “appropriate scope and configuration,” which means that it must be geographically large enough to satisfy the Commission on that characteristic. However, FERC thus leaves open the possibility that there could be multiple ITPs within a very large regional RTO. If that structure is permitted, then what functions will be performed by the RTO, if it were not an ITP? Must an RTO qualify as an ITP or merely, as Order 2000 requires, ensure that particular functions are performed?

91 Ancillary services may still be procured through bilateral contract or self supplied as permitted under Order 2000.
### List of Acronyms

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
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<tbody>
<tr>
<td>A&amp;G</td>
<td>Administrative and General</td>
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<tr>
<td>BOC</td>
<td>Bell Operating Companies</td>
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<tr>
<td>COSR</td>
<td>Cost of Service Regulation</td>
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<tr>
<td>CPI</td>
<td>Consumer Price Index</td>
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<tr>
<td>CRR</td>
<td>Congestion Revenue Right</td>
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<tr>
<td>FCC</td>
<td>Federal Communications Commission</td>
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<tr>
<td>FERC</td>
<td>U.S. Federal Energy Regulatory Commission</td>
</tr>
<tr>
<td>FTR</td>
<td>Financial Transmission Right</td>
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<tr>
<td>ILEC</td>
<td>Incumbent Local Exchange Carriers</td>
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<tr>
<td>ISA</td>
<td>Independent System Administrator</td>
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<tr>
<td>ISO</td>
<td>Independent System Operator</td>
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<tr>
<td>ITC</td>
<td>Independent Transmission Company</td>
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<tr>
<td>ITP</td>
<td>Independent Transmission Provider</td>
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<tr>
<td>LSE</td>
<td>Load-serving Entity</td>
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<td>LMP</td>
<td>Locational Marginal Price</td>
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<td>MISO</td>
<td>Midwest Independent System Operator</td>
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<td>NERC</td>
<td>North American Electric Reliability Council</td>
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<td>NOPR</td>
<td>Notice of Proposed Rulemaking</td>
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<td>NYISO</td>
<td>New York Independent System Operator</td>
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<tr>
<td>O&amp;M</td>
<td>Operation and Maintenance</td>
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<tr>
<td>PCR</td>
<td>Price Cap Regulation</td>
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<td>PBR</td>
<td>Performance Based Regulation</td>
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<tr>
<td>PJM ISO</td>
<td>Pennsylvania-New Jersey-Maryland Interconnection, L.L.C.</td>
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<tr>
<td>POD</td>
<td>Point of Delivery</td>
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<tr>
<td>POLR</td>
<td>Provider of Last Resort</td>
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<tr>
<td>POR</td>
<td>Point of Receipt</td>
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<tr>
<td>ROE</td>
<td>Return on Equity</td>
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<tr>
<td>RPI</td>
<td>Retail Price Index</td>
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<tr>
<td>RSAC</td>
<td>Regional State Advisory Committee</td>
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<td>RTO</td>
<td>Regional Transmission Organization</td>
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<tr>
<td>SMD</td>
<td>Standard Market Design</td>
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<tr>
<td>SO</td>
<td>System Operator</td>
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<tr>
<td>TFP</td>
<td>Total Factor Productivity</td>
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<tr>
<td>Transco</td>
<td>Private, for-profit Transmission Company</td>
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<tr>
<td>VIU</td>
<td>Vertically Integrated Utility</td>
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Acknowledgements

I thank Doug Collins, Christina Forbes, Darrell Gunst, Ross Hemphill, Paul Joskow, Robin Kittel, Masheed Rosenqvist and Cindi Schieber for helpful comments on earlier drafts of this report.