A Review of Uniform Transmission Rates in Ontario

FINAL REPORT

Prepared for:
The Ontario Energy Board

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The views expressed in this report are those of London Economics International LLC and do not necessarily represent the views of, and should not be attributed to, the Ontario Energy Board, any individual Board Member, or Board staff.
Table of contents

CHAPTER 1: ONTARIO UNIFORM TRANSMISSION RATE METHODOLOGY REVIEW ........................................... 5
1 Study overview ...........................................................................................................................................7
2 Stakeholder feedback ................................................................................................................................. 9
3 Strategic implications and recommendations on key project issues ............................................. 11

CHAPTER 2: PRACTICAL CONSIDERATIONS FOR TRANSMISSION RATE SETTING BASED ON PRINCIPLES OF ECONOMIC THEORY ................................................................................................. 15
1 Context of study ...................................................................................................................................... 17
   1.1 Background: Evolution of US Power Pool Model and Rate Pancaking .............................................. 17
   1.2 Ontario’s Current Situation .................................................................................................................... 17
   1.3 Structure of Chapter 2 .......................................................................................................................... 18
2 Introduction to Economic Concepts and Recommendations from Economic Theory for Optimizing Pricing of Transmission Service ...................................................................................................................... 19
   2.1 Considerations of a Natural Monopoly .................................................................................................. 19
   2.2 Kirchov’s Law, Non-Exclusion, Free-Riding, and Common Pool Resources ........................................ 20
   2.3 Positive Externalities ............................................................................................................................... 21
   2.4 Implications for Rate Design .................................................................................................................. 22
3 “Best Practices” Criteria for Designing Transmission Rates ................................................................. 24
4 Classifying Transmission Rates .................................................................................................................. 31
   4.1 Connection Charges ............................................................................................................................... 33
   4.2 Congestion Charges ............................................................................................................................... 35
      Socialized congestion charges .................................................................................................................. 36
      Administrative process for setting locational charges: estimating the long run marginal cost of transmission 36
      Market pricing of transmission congestion: through LMP systems ....................................................... 37
   4.3 Access Charges ..................................................................................................................................... 37
      How are access charges calculated? ......................................................................................................... 38
      Who pays access charges? ....................................................................................................................... 39
      How are transmission access costs allocated? ......................................................................................... 39
      How does firmness relate to access? ......................................................................................................... 40
   4.4 Linkage between Congestion Charges and Access Charges ............................................................ 41
5 Concluding Remarks .................................................................................................................................. 43

CHAPTER 3: CASE STUDIES: TRANSMISSION ACCESS CHARGING PRINCIPLES ACROSS KEY NORTH AMERICAN POWER MARKETS ........................................................................................................ 46
1 Executive summary ...................................................................................................................................... 48
2 FERC’s Open Access Transmission Tariff (OATT) ................................................................................... 53
3 Alberta ISO (AESO) ..................................................................................................................................... 57
   3.1 Introduction ............................................................................................................................................. 57
   3.2 Access to Transmission Services and Related Charges ........................................................................ 59
   3.3 Linkages between Transmission Access Charges and Alberta’s Wholesale Market ......................... 62
4 California ISO (CAISO) ............................................................................................................................... 64
Table of figures

<table>
<thead>
<tr>
<th>Figure</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>FIGURE 1.</td>
<td>ILLUSTRATION OF HYPOTHETICAL EXAMPLE</td>
<td>30</td>
</tr>
<tr>
<td>FIGURE 2.</td>
<td>DEGREES OF LOCATIONAL DIFFERENTIATION</td>
<td>43</td>
</tr>
<tr>
<td>FIGURE 3.</td>
<td>DEGREES OF TEMPORAL DIFFERENTIATION</td>
<td>44</td>
</tr>
<tr>
<td>FIGURE 4.</td>
<td>OVERVIEW OF CASE STUDY JURISDICTIONS</td>
<td>49</td>
</tr>
<tr>
<td>FIGURE 5.</td>
<td>ALBERTA’s BULK TRANSMISSION SYSTEM</td>
<td>58</td>
</tr>
<tr>
<td>FIGURE 6.</td>
<td>AESO DTS RATE COMPONENTS AND RATES</td>
<td>60</td>
</tr>
<tr>
<td>FIGURE 7.</td>
<td>STS RATE AND APPLICABLE CHARGE IN AESO</td>
<td>62</td>
</tr>
<tr>
<td>FIGURE 8.</td>
<td>TAC AREAS AND TRANSMISSION PATHS IN CAISO</td>
<td>65</td>
</tr>
<tr>
<td>FIGURE 9.</td>
<td>CURRENT TRANSMISSION ACCESS RATES IN CAISO</td>
<td>68</td>
</tr>
<tr>
<td>FIGURE 10.</td>
<td>PRICES PAID BY TRANSMISSION CUSTOMERS FOR NETWORK AND POINT-TO-POINT SERVICES*</td>
<td>73</td>
</tr>
<tr>
<td>FIGURE 11.</td>
<td>MISO PRICES FOR THROUGH AND OUT SERVICES</td>
<td>74</td>
</tr>
<tr>
<td>FIGURE 12.</td>
<td>ISO-NE LOAD ZONES AND TRANSMISSION INTERTIES</td>
<td>77</td>
</tr>
<tr>
<td>FIGURE 13.</td>
<td>ISO-NE TRANSMISSION SERVICE RATES</td>
<td>78</td>
</tr>
<tr>
<td>FIGURE 14.</td>
<td>NYISO TRANSMISSION DISTRICTS AND LOAD ZONES</td>
<td>84</td>
</tr>
<tr>
<td>FIGURE 15.</td>
<td>WHOLESALE TSC CALCULATION INFORMATION BY TRANSMISSION OWNER</td>
<td>87</td>
</tr>
<tr>
<td>FIGURE 16.</td>
<td>SAMPLE TCC AUCTION RESULT- JUNE 2007</td>
<td>88</td>
</tr>
<tr>
<td>FIGURE 17.</td>
<td>OVERVIEW OF PJM’S CURRENT FOOTPRINT AND ITS EXPANSION OVER TIME</td>
<td>90</td>
</tr>
<tr>
<td>FIGURE 18.</td>
<td>MAP OF TRANSMISSION ZONES IN PJM</td>
<td>92</td>
</tr>
<tr>
<td>FIGURE 19.</td>
<td>ANNUAL RATES PAID BY NETWORK INTEGRATION SERVICE CUSTOMERS ($/MW)</td>
<td>94</td>
</tr>
<tr>
<td>FIGURE 20.</td>
<td>LONG-TERM/SHORT-TERM FIRM AND NON-FIRM POINT-TO-POINT RATES BY ZONE (IN $/MW)</td>
<td>95</td>
</tr>
</tbody>
</table>
Chapter 1: Ontario uniform transmission rate methodology review
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preparing for the Ontario Energy Board (OEB)

February 29, 2007

London Economics International LLC (LEI) was retained by the Ontario Energy Board (OEB) to review its uniform transmission rate methodology to determine whether it remains appropriate for Ontario. This Chapter's primary objectives are to discuss the scope of the study conducted, summarize key conclusions from the other Chapters, review the feedback received from stakeholders on the topic of transmission rate design in addition to providing the OEB with strategic implications resulting from the stakeholder comments received.

Based on our review of industry practices in other jurisdictions and given the current situation in Ontario, we believe that, generally, the uniform transmission rate concept is appropriate for Ontario. However, the OEB may want to consider some adjustments in particular aspects of transmission regulation which ultimately have implications on transmission rates in Ontario. We, among other things, recommend that the OEB review the possibility of gradually moving towards a form of long-run marginal cost based pricing that is zonally differentiated; revisit the pricing of “through and out” service; and progressively introduce performance-based ratemaking in transmission regulation.
1 Study overview

London Economics International LLC (LEI) was commissioned by the Ontario Energy Board (OEB) to review the uniform transmission rate methodology in Ontario and other jurisdictions to develop a recommendation on whether such a methodology remains appropriate for the province of Ontario.

The study was conducted in four separate phases with each phase resulting in a separate deliverable. These deliverables have been subsequently combined into this one report. An initial Chapter entitled “Practical considerations for transmission rate setting based on principles of economic theory”, issued on November 15th 2007, provided the theoretical foundation on the economic principles of transmission access charging. That Chapter was subsequently followed by a Chapter on case-studies issued on November 19th 2007 and entitled “Case Studies: Transmission Access Charging Principles across key North American power markets” detailing how various transmission access charging issues are dealt with in other jurisdictions. The third phase of the study involved interacting with key Ontarian stakeholders on major transmission rate design principles and current practices. Questionnaires were sent out in November and received back by LEI over the course of December 2007 through February 2008.

Finally, those stakeholder comments received have culminated into the production of this Chapter which also includes final recommendations.

The various deliverables produced to date by LEI for the OEB have focused on addressing the key issues specified in the project RFP, which notably include:

- the appropriateness of uniform rates when transmitters’ revenue requirements differ;

Update on the Midwest ISO-PJM’s inter-RTO rate design

In our Chapter on case studies we describe at length the transmission pricing arrangement between PJM and the Midwest ISO.

On February 1st 2008, FERC accepted the inter-RTO rate design put forth by the Midwest ISO and PJM for transactions between them. The rate design is intended to allow for the cost of existing facilities to be recovered from customers within the zone where the facilities are located and that of new inter-RTO facilities to be divided between the two RTOs. The rate design had been opposed by American Electric Power (AEP) who advocated a postage-stamp rate design for all new high-voltage facilities in the Midwest ISO-PJM region.

FERC stated that the approved rate design incentivized the build of transmission infrastructure that performs inter-RTO functions. Interestingly FERC noted that rate design “is less a science than it is an art” because the allocation of costs involves a fair amount of judgement.
• practical aspects of the computation of uniform rates, including use of transmitters load forecasting methods;

• treatment of “lumpy” transmission investments within transmission access charges; and, more generally,

• lessons learned from other jurisdictions by way of a case study review of approaches in other jurisdictions.

Furthermore, we have also reviewed the locational pricing arrangements in other jurisdictions’ wholesale energy markets and discussed how those market design choices interact with transmission access charging methods; and we have detailed the various related issues that have arisen as a result of the Federal Energy Regulatory Commission’s push in the US for measures that reduce rate pancaking within and across RTOs.
2 Stakeholder feedback

LEI conducted stakeholder interactions for this study through a questionnaire developed jointly with the OEB staff and sent out for comment to key stakeholders, notably Hydro One Networks Inc. (HONI), Great Lakes Power Limited (GLP) and the Association of Major Power Consumers in Ontario (AMPCO). The highlights of the responses received by these stakeholders are summarized here.

Stakeholder questionnaires were designed to solicit comments on two main elements: current transmission charging related arrangements in Ontario and transmission charging related arrangements in other jurisdictions that could potentially be applied in Ontario.

With regards to current practices in Ontario, stakeholders were asked, primarily, whether these adequately compensated transmission providers; accounted for differences in load growth; and resulted in cross-subsidies among transmitters.

- HONI responded stating that the current postage stamp system does equitably compensate transmitters for their cost because these transmission access charges are established through a transparent process under the OEB’s oversight. It also stated that these access charges account for any potential difference in load because the load forecasts are developed by each transmission provider for their service territory. However HONI pointed out that the current system does result in smaller transmission providers being inefficiently cross-subsidized because of the impact that a difference in the demand component (load change) in HONI’s service territory may have on increasing other transmitters’ revenue requirement through the postage-stamp system. Yet, HONI believes that this cross-subsidization is relatively small.

- GLP also stated that the current postage stamp system equitably compensates transmitters through the proportional sharing of transmission revenues. With regards to adequately accounting for differences in load growth across service territories, GLP did not directly answer the question but instead pointed out that load forecasts would be better if conducted by the IESO. However, GLP did not agree with HONI that the current charging system results in cross-subsidies to smaller transmitters.

- AMPCO agreed that the current transmission rate design adequately compensates transmission owners. AMPCO did acknowledge however that the current system does lead to cross-subsidies but stresses that these are likely marginal given the comparatively smaller size of the non-HONI transmission providers.

With regards to current practices in other jurisdictions that could potentially be applied in Ontario, stakeholders were asked, primarily, to comment on a license-plate (zonal) charging system and the impact its implementation could have in Ontario; a differentiation in rates based
on the transmission asset being used and transmission service type; and on the treatment of deferral accounts and transmission upgrades.

- HONI stated that each transmitter having separate charges reflective of characteristics intrinsic to their service territory will result in more efficient transmission investment. HONI further argued that zonal pricing would be an improvement over the current postage stamp system because it would send better price signals to generators and load in terms of location. However HONI is somewhat opposed to any rate differentiation across asset class lines because it argues that such a mechanism would not take into account historical investment considerations. Lastly HONI stated that “through and out” charges, as currently in place in Ontario, need not change until such time as they are revisited in coordination with neighboring jurisdictions.

- GLP argues that zonal transmission charging would not be fair nor economically efficient because it would unfairly assign the cost of the transmission system to customers in Northern Ontario who are not the main beneficiaries of the transmission investment there. GLP also put forward the current socio-political environment as an argument against zonal pricing of transmission. Furthermore GLP argues that differentiating transmission rates across asset classes would have little merit due to the homogeneity of the transmission consumers. Finally GLP thought there might be some merit in revising the current “through and out” (export) charging policy in Ontario to reflect actual market conditions.

- AMPCO is concerned that a zonal based charging system would have little impact on transmission investment efficiency given the current market environment in Ontario, where supply decisions are actively managed by the Ontario Power Authority (OPA), rather than market forces. AMPCO's view on the pricing of transactions in and out of Ontario is that it could benefit from some fine tuning primarily in compensating Ontarians for the congestion these transactions cause on the network.
3 Strategic implications and recommendations on key project issues

The feedback received from the stakeholders coupled with the economic theory and practical examples laid out in the previous two studies submitted to the OEB allow us to draw a few conclusions with regards to the potential evolution of transmission rate design in Ontario. While we do believe that the uniform transmission rate design is appropriate for Ontario, we do however recommend that the OEB explore the possibility of modifying a few elements concerning the regulation of transmission in the Province.

Although there was no resounding criticism of the uniform transmission rate concept, and even though Ontario has a relatively small geographical footprint (in comparison to PJM, for example), there seems to be some interest and even a clear preference by some to move away from a universal postage stamp charging process towards some form of long-run marginal cost (LRMC) pricing that is zonally differentiated. LRMC based charging is used by the transmission provider National Grid (NGC) in the United Kingdom and effectively combines the concepts of congestion, investment and ongoing operating costs in the access charge determination1. HONI believes that such a system would not only give loads the appropriate price signals but more importantly give an indication to generators (or, in the current case, policymakers that are managing and coordinating investment) on where to site facilities depending on cost signals. This, of course, implies that generators would also have to be responsible for some portion of transmission costs. This view of zonal charging providing for better price signals to generation is shared by GLP and AMPCO. However it is worthwhile to note, as has been pointed out in the stakeholder feedback, that the move to LRMC pricing would have to occur in conjunction with other market evolutions in Ontario. Clearly there is some concern that in an environment where the OPA plays a prominent role in generation supply procurement and where the composition of the fuel-mix in the Province is defacto determined by the IPSP, the implementation of such a pricing mechanism would not fulfill its objectives.

Furthermore, the move to a zonally differentiated LRMC pricing system could over time do away with the (marginal) cross-subsidization that most stakeholders mention occurs between HONI and the smaller transmitters. Such differentiation will not cause rate pancaking, as that would be controlled for by charging principles (i.e., user pays the charge for the zone where it is located, regardless of where the energy is actually transmitted to/from in the Province).

It is interesting to note that HONI is however against any differentiation on the basis of asset/customer class (i.e. high voltage-uniform versus low voltage-zonal). Its main concern

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1 Under this mechanism, NGC applies an administrative process to determine zonal long term cost-based transmission rates under its investment cost-related pricing (ICRP) model. NGC uses incremental capital cost models of the transmission network to estimate the extra transmission investment costs (combining capital costs and usage/congestion costs) that would be needed to meet a 1MW increase in generation or demand between specific nodes along the network. NGC’s model’s outputs are grouped on a zonal basis for simplicity and stability in tariffs.
seems to be linked to the fact that the transmission system was primarily built by the old provincial utility Ontario Hydro as a common public good and so revisiting these historical investments in light of a differentiated charging mechanism might prove complex and inefficient. As illustrated in the case studies of PJM and California, a distinction between access charges for transmission assets classes (or that serve different customer classes) has some merit. Indeed, as discussed in our previous study on the underlying economic principles of transmission access charging, there is a greater justification and efficiency in socializing the cost of high-voltage transmission assets which typically serve as the network “backbone” and thus benefit all consumers; and using a zonal differentiation for low-voltage transmission assets that typically benefit those consumers within the area in which the transmission assets are located. Based on the feedback received from HONI, we feel that such a distinction in the transmission access charging mechanism, if applied solely to future transmission investments, would avoid HONI’s accounting concerns and may be worthwhile to consider.

In addition, there seems to be a consensus that the current charging of “through and out” transmission service (currently priced at $1/MWh for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province, irrespective of whether this energy is supplied from generating sources within or outside Ontario) could benefit from a review primarily because it has not really resulted in the efficient utilization of the network. In fact, AMPCO claims that it has created congestion. Typically, demand for “through and out” transmission service is highly volatile from one period to another and price sensitive because of the economics of the underlying transactions they facilitate (i.e. arbitrate opportunities with neighboring jurisdictions). Such transactions are not only dependent on the commodity prices for electricity but also on transmission system charges that the consumer must pay and are therefore highly susceptible to price variations (i.e. have an elastic demand). It may be useful for the OEB to initiate a study into the “through and out service” that would pinpoint the underlying conditions of usage of the interties and methodologically establish a charge rate that represents (or at least balances) the opportunity cost of use with the goal of maximizing revenues generated by cross-border transactions (so that the revenue requirement on native load consumers is reduced). We would also recommend that the OEB authorize the IESO to pursue efforts to calibrate such charges with neighboring markets of New York ISO (NYISO), Midwest ISO (MISO), and the TransÉnergie (HQTE) system. Such an effort would also improve the long run efficiency of markets by eliminating rate pancaking at Ontario’s borders.

Another issue which the OEB may want to further explore is related to the cost of service approach to developing the transmitters’ revenue requirements. From the feedback received, there seems to be some consensus regarding the fact that the process is cumbersome and not entirely efficient primarily in how it deals with capital expenditures incurred by transmission owners to maintain and upgrade the network. This issue has challenged regulators worldwide and has generally resulted in substantial regulatory costs for both the applicants (utilities) and the regulator.
The OEB has a history with and is further evolving its incentive-based ratemaking arsenal for Ontario in its regulation of other industries, like gas distribution and electricity distribution and we understand that such a form of regulation for transmission is foreseen in the short to medium term in the form of a revenue cap. Although it may be premature to consider a price-cap regime for Ontario’s transmission sector, the OEB may be interested in evaluating other forms of incentive-compatible ratemaking.

For example, in order to deal with the prudence reviews for capex (with the embedded information asymmetries and incompatible incentives between regulator and regulated firm) the OEB should consider developing a incentive-based scheme that would aim to reduce the regulatory burden and information asymmetry problem, by rewarding utilities for accurately forecasting and disclosing their capital expenditure needs. The textbox to the right describes an innovative approach developed in the UK by Ofgem and applied to the electricity distribution networks to facilitate the capital expenditure scheduling and approval process, and the inherent review of under- and over-spends. We are not suggesting that such a mechanism be applied to Ontario as is but that the OEB explore the potential applications of certain of its concepts (in a tailored approach). It is worthwhile to note that Ontario will need large amounts of capital investment in the coming years and that, as HONI has pointed out, the current regulatory process involving capital expenditures is cumbersome because it requires transmitters to go through a three-staged process (siting, licensing and rate determination). A streamline of that process could help facilitate new transmission investment in the Province.

OFGEM’s “menu of contracts” system in the UK

To address the potential for regulated companies to over inflate their expenditure plans and earn extra profits from “saving” costs, (i.e. not incurring costs that were not meant to be incurred in the first place), while regulators are not able to assess the true needs for expenditure, OFGEM has used a “menu of contracts” method developed by Laffont and Tirole.

The approach, intended to deal with this “asymmetry of information” problem, is based on a premise that a menu of contracts can be designed to give the right amount of incentives to every entity to provide reasonable estimates of their true investment needs and penalize them if the information is misleading. Under this sliding scale mechanism companies are able to choose an implicit “regulatory contract” that provides the best incentive to declare most accurate investment plans.

This approach is not without its flaws as it, in its current form, provides best incentives when companies are providing investment plans in line with the regulator’s estimate of investment needs. Nevertheless, this issue is a question of how the idea is put into practice, and not a defect of the concept. See:http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/Pages/PriceCntrls.aspx for more information
Lastly, the issue of load determinants used in the calculation of the access charges could also benefit from a review. Currently in Ontario transmitters use own load forecasts developed for their respective service territories. It has been suggested that the IESO would be well-placed to make such load forecasts, and that it would instill a level of independence into the rate-setting process. AMPCO has argued that the current use of forecasts done by transmitters themselves results in a conflict of interests and has pointed out that it “encourages a transmitter to low-ball the estimate in the hope that it may receive excess revenue when actual demand exceeds forecast”. It further pointed out that over the past six years actual average monthly demand exceeded the forecast, which suggests that transmitters may have shown some form of bias in the past. While HONI has stated its opposition to this idea for reasons of accountability, we encourage the OEB to explore the option of potentially using the IESO’s load forecast as the standard load determinant in charge computations. Another plausible alternative could be to move towards historical accounting whereby historical measures of load could be used to set the rate forward. Both practices are common in other North American jurisdictions, as we have highlighted in our previous case studies. In New York, a load forecast conducted by the NYISO is used to set transmission rates for individual utilities, whereas jurisdictions like MISO use a historical measure of coincident peak demand.

\[2\text{ Potentially normalized for weather for better accuracy.}\]
Chapter 2: Practical considerations for transmission rate setting based on principles of economic theory
Chapter 2: Practical considerations for transmission rate setting based on principles of economic theory

preparing for Ontario Energy Board (OEB)

December 3, 2007

London Economics International LLC (LEI) was retained by Ontario Energy Board (OEB) to review the uniform transmission rate methodology to determine whether it remains appropriate for Ontario. The primary objective of this Chapter is to discuss the economic drivers behind transmission rate design, present a broad overview of the different types of transmission charges, describing the economic rationale for each, and build a robust foundational understanding of the concepts and tradeoffs that regulators need to make in rate design projects. Chapter 3 contains a series of case studies which further highlights how economic considerations have been applied in practice in other jurisdictions with respect to transmission access rates.

Transmission ratesetting needs to systematically address the economic traits of the product or service being offered, in order to ensure that rates achieve their final objective. In the first section of this Chapter, we describe the fundamental economic issues associated with transmission. For example, transmission services are typically provided by a natural monopoly; therefore, it is not typically considered a “market-based” product for which (short run) marginal cost pricing techniques could be applied effectively. In addition, transmission services have economic features that make it difficult to exclude users and identify beneficiaries. Furthermore, provision of transmission is primarily based on fixed costs rather than variable costs. In order to overcome the potential for “free-riding” by users (who will utilize the network but not pay for access), transmission services are typically regulated. As a result, access rates (including connection charges) are designed with a long run cost recovery objective whereby the transmission service provider would be allowed to recoup the fixed costs of its transmission investment over the long-term. Such an economic policy is primarily intended to assure the long run sustainability of investments in the transmission sector. There are a number of dimensions to long run costs of transmission and overall rate optimization, given the economic issues with transmission. The second section of this Chapter provides a list of specific criteria that should be considered in the design of transmission rates.

The third section of the Chapter then continues with an overview of the different types of transmission rates, and the options for defining and allocating transmission costs. For example, transmission costs can be socialized and a uniform tariff charged to all users in a jurisdiction, or costs can be allocated differentially, for example, on a zonal basis or even differentiated by customer class. The differences in approach relate primarily to the trade-off between the objective of applying cost causation/user pays principles versus simplicity in application. The differentiation can be accommodated without instigating rate pancaking. It is also possible that differentiated tariffs can improve the overall situation for all users of the transmission system.
Transmission ratemaking choices can facilitate (or impede) trading and therefore one needs to also consider how transmission rate design choices influence (and interact with) the development of the wholesale power market. Rate pancaking can be removed to bolster trading under both a uniform and zonal (or locationally differentiated) tariff approach; therefore, this is not the decisive factor in the choice of a uniform or zonal tariff structure. Rather, the key economic issue with respect to transmission tariff design relates to whether there are legitimate cost differences and how a particular transmission access tariff structure impacts investment decisions. Given the focus outlined in OEB’s scope of work, the last section of this Chapter discusses the conceptual linkages between different types of transmission rates (access and congestion), as well as the implications for investment with different types of access tariff structures.

1 Context of study

1.1 Background: evolution of US power pool model and rate pancaking

Prior to deregulation in the United States, electricity utilities were vertically integrated and provided a bundled service to customers in their franchise area. Although, the utilities planned to be self-reliant, they did organize themselves loosely into power pools. These were initially set up to improve reliability (after the Northeast blackout of 1965) by allowing interchanges between neighboring utilities, without the system operators having to bilaterally negotiate each individual transaction. Three such pools were initially setup in the US, notably PJM, the New England Power Pool and the New York Power Pool. As these power pools evolved through deregulation and the advent of transmission open-access, requests for trades stemming across control areas external to the pools added a layer of complexity to the transmission pricing arrangements. Indeed, it was to solve issues relating to loop flow and pricing of cross-area trades that FERC pushed for the creation of Regional Transmission Organizations or RTOs. These would expand each market’s geographical footprint and harmonize internal transmission pricing mechanisms thereby laying the foundation for the progressive elimination of any duplicate costs related to transmission across control areas, or rate-pancaking.

1.2 Ontario’s current situation

In Ontario, the situation is different due to this lack of a transition from an initial power pool. Indeed, rate pancaking in the province is largely unrelated to the type of transmission pricing mechanism employed for internal transactions. There has been a uniform tariff in place in Ontario for internal transactions for some time. And as we discuss further below, a license plate tariff (for example, differentiated by transmitter) could be employed without fear of rate pancaking so long as arrangements for revenue sharing are accommodated in the design.

Rate pancaking in Ontario’s context occurs on transactions that originate in Ontario and sink into neighboring control areas, and those transactions that originate externally and sink in
Ontario. Transactions such as these have to pay Ontario’s transmission tariff and that of the neighboring control area; exports out of Ontario must also pay the $1/MWh export tariff. Therefore, Ontario has rate pancaking at its borders. Elimination of rate pancaking at the border can be achieved through arrangements similar to those in place between MISO and PJM where ‘through and outs’ charges were eliminated and tariffs collected on inter-jurisdictional transactions are pooled. The transaction sponsor does not need to pay ‘twice’ for transmission service. Although these arrangements are discussed in greater detail in our subsequent Chapter to the OEB on transmission pricing case studies, it is important to keep in mind that such accommodations do have precedent and could be implemented in Ontario to reduce ‘at the border’ rate pancaking. It is worthwhile to add that the elimination of rate-pancaking at the border can potentially have a beneficial impact on transmission charges for native load customers. Indeed, as is discussed in the later sections of this Chapter, lower transmission tariffs can result in an increased volume of transmission transactions, particularly on an underutilized system or transmission path. Such an increase in volume of throughput on the system in turn generates revenues above and beyond those initially forecast. Since the transmitter is supposed to recover no more than its regulated revenue requirement, these incremental revenues from higher inter-jurisdictional trading volumes can provide an opportunity for rate reductions for native load.

1.3 Structure of Chapter 2

This Chapter discusses transmission rate setting by first detailing the economic concepts that drive transmission rate design and then explaining how these ultimately affect the optimal charging structure to be adopted. The economic theory in Section 2 lays the foundational framework within which the common design approaches to transmission price processes are discussed in Section 3. Section 4 then provides an overview of the basic types of transmission pricing arrangements, namely transmission access charges, connection charges, and usage charges (otherwise known in many jurisdictions as congestion charges).

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³ Also discussed in February 2005 Spark article entitled “Transmission Pricing – FERC fixes rate pancaking, but at what cost?”, Lori A. Burkhart.
2 Introduction to economic concepts and recommendations from economic theory for optimizing pricing of transmission service

Transmission service refers to the transmission of power from one intake point (source) on the network to an output point (sink). This service, albeit seemingly simplistic, has a host of peculiar characteristics that render it’s pricing somewhat complex primarily due to the nature of the service being provided. Transmission networks are natural monopolies. Usage is difficult to deny once a customer is interconnected. Beneficiaries are hard to identify. And indeed, customers are not properly incentivized to reveal their true valuation. Positive externalities are also common, where some transmission customers may benefit from transmission investment through indirect improvements in system-wide reliability. In identifying these characteristics, economic theory suggests that transmission services would be under-provided if regulators do not step in and regulate access and set prices (tariffs). Furthermore, with such characteristics, economic theory suggests that socialization of costs – through uniform or postage stamp pricing – is more efficient for ensuring sufficient volumes of service.

2.1 Considerations of a natural monopoly

First and foremost, electricity transmission is considered a natural monopoly because of the necessary economies of scale for investment. It would be highly inefficient from an economic standpoint and practically difficult from a siting standpoint to have multiple – competing - transmission systems delivering to the same user. As such, transmission service must be regulated in order to insure fair and open access to the network and reasonable pricing.

Regulation also assures transmission owners (TO) that they will recover their investment and earn a reasonable return on that investment. The price for transmission services cannot be set by reference to marginal costs, as is common for many industries, because the short run marginal costs of transmission service provision are close to zero for most periods. Rather, prices or tariffs for access need to be designed such that the TO recoups on average over time the fixed costs of investment. Indeed, as we discuss in more detail later in the Chapter, the large majority of the costs associated with the transmission network are fixed (i.e. sunk costs). Therefore a fixed access charge best meets the underlying characteristics of transmission service provision. Transmission usage charges based on how users “value” transmission access at the margin have historically never been implemented, because so long as there is excess capacity on the system, the ‘marginal value’ will tend to be close to zero.4

4 However in systems with locational based marginal pricing (LBMP), a marginal pricing framework has been implemented in the form of transmission congestion charges. These charges are designed to cover the costs of congestion on the network in addition to line losses. However, given that users have already paid for all the costs of the service through regulated access charges, revenues from congestion are generally credited back to those users (customers) that have paid the access charge. In essence, the access charges allow those customers that have paid to be entitled to use the system to also benefit from its use.
2.2 Kirchov’s Law, Non-Exclusion, Free-riding, and Common Pool Resources

Another very important feature of transmission service is that it cannot be controlled physically. Due to the physical nature of transmission systems – as documented by Kirchov’s Law in physics - the flow of power on the network cannot be controlled (although it can be managed), and therefore a TO cannot practically exclude a user of the transmission network once that user has access to the network.5

This technical characteristic creates what is known as the “free rider” problem in economics. If a user knows that it cannot be excluded from receiving the benefits of the service, he will not want to pay. Nor will he reveal his preferences or private value for the service. In fact, this same technical problem with physical flows and user’s perverse incentives makes it that more difficult to precisely indentify all beneficiaries of transmission access (prior to actual usage). On this same basis, transmission users are not motivated to reveal how they value the service.

This non-exclusionary aspect of transmission services is one of the characteristics commonly associated with a common pool resource, which is a variant of the “public good.” As described in the textbox above, the primary theoretical characteristic of public goods is non-rivalry in consumption. Transmission services do not hold to this property at all times, because, in fact, transmission capacity is finite and when it is at its limit, one user’s consumption could impinge on another user’s consumption.

That being said, the same general considerations apply to common pool resource as to a public good: the fact that it is practically difficult to exclude users of transmission services.

Defining Public Goods: In the classic 1954 paper The Pure Theory of Public Expenditure, Paul A. Samuelson laid out the theory of public goods. In his paper, he defined a public good on the basis of non-rivalry in consumption, where “each individual’s consumption of such a good leads to no subtractions from any other individual’s consumption of that good”. In addition, economists define a pure public good if it is non-excludable in consumption. In other words, it is impossible to (practically) exclude any individuals from consuming the good.

A good or service which is subject to rivalry in consumption but is non-excludable is sometimes called a common pool resource. Such goods raise analogous ‘market failure’ problems to public goods: common pool resources face the threat of congestion and overuse by in the private sector while public goods face problems of underproduction by the private sector.

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5 It is possible for the status of a public good to change. For example, radio waves were traditionally considered public goods because they were non-rivalrous and non-excludable in consumption. However, technological innovation has allowed broadcasters to encrypt radio signals and thereby control access to their programs. DC networks are an analogous technological solution in the power sector; as power flows on a DC transmission line can be controlled. However, implementing DC technology exclusively in place of AC systems would be too costly and technically impractical.
capacity (once they are interconnected) and also difficult to isolate beneficiaries (in order to require payment of them) may lead to under-provision. Economic theory – based on observations from the real world - predicts this under-provision. Therefore, pricing of transmission services needs to account for the public good paradigm in order to make sure there are sufficient ‘quantities’ of transmission capacity available to meet users’ needs.

If transmission service does indeed benefit everyone – as would be suggested by a public good classification – then it is reasonable to price the service so that all users contribute equally. In other words, if the benefits are wide and diffuse from a particular transmission service, economic theory suggests that uniform tariffs, that socialize costs across the entire spectrum of users, would be most efficient.

2.3 Positive Externalities

The public good problem is also related to another class of market failures in economic theory: namely the presence of externalities. A positive externality occurs in the situation where there are indirect social benefits of a good or service that do not register on producers as no market exists in which they are traded. These benefits will likely be under-produced. Transmission services can create positive externalities, where some consumers can take advantage of transmission infrastructure without contributing sufficiently to the (costs) of their creation.

For example, the construction of transmission infrastructure may improve system performance not only for the interconnected customers in the vicinity of the transmission augmentation but also for transmission users that are remotely located (and difficult to identify). In another example, transmission investment to interconnect a new transmission customer can also improve the overall system reliability, therefore indirectly benefiting all users on the system in addition to the newly interconnected customer. In addition, construction of additional transmission may create positive spillover effects for all consumers because it also bolsters competition and opens access to cheaper generating resources from other markets, which may have an impact on the commodity price of electricity.

Social benefits of a transmission investment can exceed the readily identifiable private benefits, because it is hard to identify all benefits and all beneficiaries of transmission infrastructure. The graph to the left highlights how such a situation would be represented using supply and demand curves in economic theory: there are effectively two demand curves for services – one representing the marginal social benefits and one representing the marginal private benefits.

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6 Indeed, pure public goods, like national defense, are typically funded by taxation, as the private sector may not be able to provide this service at all.

7 Conversely, it is also plausible that the interconnection of a new resource can increase congestion for other users and therefore result in a negative externality. We discuss this possible outcome in Section 4.1.
In evaluating the economic benefits of transmission, policymakers are increasingly recognizing the importance of incorporating all positive externalities in the full cost accounting of a project that is used to rationalize the investment. Without consideration of such externalities, some investments would not proceed, although they may be socially beneficial. The under-provision arises because of misaligned incentives between customers and the TO: if users can take advantage of transmission infrastructure without sufficiently paying for it, then the TO will not have sufficient incentives to make the investment in the first place.

Furthermore, to the extent that substantial positive externalities have been identified, then economic theory suggests that tariffs that socialize the costs of transmission would be best to offset the ‘free riding’ problems. Indeed, given the fact that there are economies of scale with transmission infrastructure (as the voltage size of the new line or the substation is expanded, then more power can be transmitted), there is even greater risk posed by the positive externality problem: the “efficient level” or “scale” of transmission investment may not be achieved if we do not take into account all possible externalities, and beneficiaries.

2.4 Implications for rate design

There are a number of practical implications from these insights from economic theory. First and foremost, the public good nature of transmission and the potential for positive externalities suggests that there is a need for regulatory oversight and coordination of transmission investment, otherwise too little transmission investment will take place. The public good nature of transmission and potential for positive externalities also has implications for ratemaking. Equity and economic efficiency is correlated with proper assignment of costs to beneficiaries, so as to motivate efficient consumption and discourage free riders. The more that a transmission investment has the characteristics of a public good, the more efficient it is to charge all potential network users for access to the network. On the other hand, the more that a transmission investment can be viewed as a private good, the better it is to charge most of the cost to the identified users.8

8 This basic logic supports the typical structure of connection charges.
As we discuss further in the companion Chapter with case studies, such arguments have been applied to ratemaking in a recent FERC decision on transmission cost allocation for PJM. FERC recommended a uniform (postage stamp) rate for high voltage transmission (which benefits the broader system), while advocating the retention of zonal (“license-plate”) rates for access to lower voltage (existing) transmission in order to provide stability in rates and prevent cost-shifting between transmission providers.

In addition, pricing of transmission services needs to work symbiotically with the operation of the wholesale energy markets, and in so doing, provide for fair and open competition for transmission services (open access), enhance trading across markets (to take advantage of market opportunities and lower the cost of power), and minimize the potential for inefficient decision-making by market participants in response to transmission ratemaking choices (for example, by reinforcing market signals regarding the siting of new generation). Indeed, some policymakers go so far as to suggest that transmission pricing should ideally enhance the operation of the wholesale power market, by removing obstacles for free trade, such as rate pancaking, which we conceptually describe on the next page.

**Introduction to rate pancaking**

This phenomenon of rate pancaking refers to a condition where a transmission user is charged separate charges by each transmission provider for moving power over each transmission provider’s service area. For example, assume a transmission user wants to move power from zone A to zone B in the example below, rate pancaking would occur if he was charged $12 per kW ($5/kW plus $7/kW) for each kW-hour of transmission capacity. Removal of pancaking reduces barriers to competition and what many view as the “fixed transaction costs” for trading.

One way to eliminate the rate pancaking is for the TOs to come together and design a single charge for cross-border trades that will remunerate them sufficiently. If the new single rate is some weighted average between the two local access charges, it will produce a rate reduction for the user, and may motivate additional trades, which will further compensate the TOs. For example, reducing the total access charge levied on a transmission user from $12/kW-hour to $10/kW-hour will improve incentives for trading between Zone A and Zone B by providing for increased opportunities for economic transactions, since the threshold for economic transactions has been lowered (price differences between Zone A and Zone B need to be only greater than $10/kW-hour to rationalize a trade).

Increased volumes could mean even further reduction of this de-pancaked access charge. From the TOs’ perspective, their focus is on assuring revenue sufficiency. As such, their prerogative is to design access rates and arrangements that allow them to recover their costs given their anticipated level of trades between zones A and B. In recognition of increased trading due to de-pancaking, the TOs may require a lower tariff to achieve the same level of revenue requirement. Due to reduced costs to users, facilitation of trading, and potential for rate reductions, rate de-pancaking is commonly
accepted as an improvement over a situation where a customer needs to pay a transmission charge for each area his transaction crosses.

However, the complexity of this improvement arises in application. How to remove rate pancaking? One approach is to use a single, blended rate - a universal tariff that would adequately remunerate transmission providers in Zone A and B (as described in the above simple numerical example). Typically, the TO in zone B would collect the transmission charges on flows into zone B, while the TO in zone A would do the same for transactions sinking in zone A. Then, there would be a settlement or redistribution of collected tariffs based on the negotiated arrangements between TOs. Another approach requires a specified arrangement between Zone A and Zone B transmission providers (for example, where transmission users are charged only the appropriate rate of their local transmission provider (i.e., on the basis of where the power originated (for generators) or where it was consumed (for load)), but are able to access the entire system. In such a case, the transmission providers must take into account the reality of such arrangements when setting their tariffs. The former concept is essentially the premise behind universal postage stamp access rates in a system, while the latter is an example of the “license plate” rate - customer pays on the basis of his location but can ‘drive’ anywhere on the system.

3 “Best practices” criteria for designing transmission rates

It is generally straightforward to establish the actual physical costs of transmission infrastructure, but the question of allocation of these costs is much more complex issue because of the dichotomy between the sunk or fixed costs of investment (which the transmission provider needs to recover) and the value of transmission within the context of wholesale markets. This leads to competing objectives between the “supplier” of transmission service (the TO), and the customer (user). Indeed, whereas the TO approaches this issue from a cost recovery standpoint, the customer will approach it from a value perspective. The customer’s perceived value for access to transmission service will be based on the nature of the transaction the customer is requesting transmission service for. That value will be equal to the opportunity cost savings generated by the trade, namely the difference in the costs of power between the source and sink (so if the cost of securing energy imports is $45/MWh and that allows the transmission customer to avoid purchasing local power at a price of $60/MWh, then the customer’s will notionally value the transmission access at $15/MWh). If the energy price differentials are small in a specific period, then customers of transmission service will price the marginal value of transmission access for this period as very low, and vice versa. This marginal value proposition can impede a TO’s revenue recovery objectives: once transmission is built, it will effectively remove all congestion and equalize the price of energy between sink and source. Therefore, going forward, customers will not put a high value on that transmission service, and if transmission access pricing was based on these marginal values, the TOs would not be assured of sufficient recovery of fixed costs of investment. Therefore, transmission service needs to priced according to mechanisms that reflect the fixed nature of transmission construction and operation costs. As such, transmission service, unlike other goods and services, cannot be priced on a marginal cost basis.
For many transmission elements, the marginal value or opportunity cost is generally much lower than the fixed costs, because it is non-zero only during periods of congestion. Therefore best practice in ratemaking suggests that sunk costs should be recovered from beneficiaries on a fixed basis through a non-bypassable access charge, so that all customers are charged equally. Such an approach means that all users pay and therefore transmission providers are insured of revenue recovery.

In addition, access rates need to be designed so that they do not distort the short run decisions of consumers and producers; for example, so that they do not interfere with trading opportunities (removal of rate-pancaking goes a long way on this front). Indeed, the short-run decision of consumers and producers should only be affected by short run marginal costing considerations, which as we discuss further below, are based on the value of having one additional increment of transmission capacity, which, in turn, is effectively related to the cost of relieving congestion.9

In some jurisdictions, transmission access charges are complemented by transmission usage charges which are designed to recover the short-term marginal cost of transmission, such as congestion and marginal losses. This is accomplished through LBMP in the wholesale market and sale of financial transmission rights (FTRs). This type of tariff (market) design requires some accounting mechanisms to ensure that transmission users (who have already paid for the infrastructure through access charges) get the benefit of congestion revenues from the sale of FTRs or are otherwise allocated those FTRs.

As can be discerned from the above discussion, there are a number of objective criteria that should be considered in the design transmission rates. Such criteria are related to the underlying economic characteristics of transmission, and also include practical objectives from the broader category of “regulatory” best practices. Below is a set of reasonable criteria which rate designers and regulators have used for framing the transmission rate design challenge. Some of the criteria are based on commonly accepted regulatory protocols, applicable to many industries, while others are specific to the electric transmission sector:

1. construct rates that are fair and equitable – rates that follow principles of cost causation, otherwise known as beneficiary (user) pays;

2. match fixed costs to non-bypassable fixed rates (therefore, the fixed rate is charged to everyone and anyone who wants to use the infrastructure; the fixed rate is developed based on levelized all-in costs of transmission). The TO earns the full cost of investment

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9 Because transmission services are not a pure private good, and are in fact difficult to price on a marginal cost basis. Thus, short run marginal costing approaches that lead to social welfare maximizing equilibriums in other markets do not wholly apply – otherwise, we would get substantially less transmission infrastructure than what is in the best interest of society. Please also refer to footnote 13 and 14 of this paper.
with time. As there are no significant variable O&M plans for transmission of this
design, there are no variable O&M expenses. Therefore, it is natural that the access
charges are denominated in fixed, capacity terms.\textsuperscript{10} In some markets, the implications of
a common pool resource characterization are explicitly captured through congestion
charges, which are based on the relative differences in LMPs. Such costs are “variable”
by definition and therefore need to denominated in variable terms ($/MWh) so that
marginal cost pricing principles are adhered to;

3. provide for stable and predictable rates, so market players can make long term
investment decisions with some certainty;

4. encourage efficient investment, so that the right type of infrastructure is built where it is
needed taking into account the trade-off between transmission and generation solutions;

5. minimize market distortions created by transmission ratemaking design choices, for
eexample eliminate pancaking to improve trading, motivate efficient utilization (consumption) of the transmission system across customers, and do away with perverse incentives to bypass the transmission system; and

6. strive for rate design that is practical and easy to administer.

It may not always be possible to achieve simultaneously all the listed objectives. For example,
the goal of practicality typically conflicts with more complex rate structures that are introduced
to meet the objectives of the other criteria, like improved efficiency. Also, there will be a natural
tension in rate design between motivating short-term efficient use of existing infrastructure and
incentivizing long term new transmission investment. Policymakers will need to make a
tradeoff and prioritize objectives, subject to the policy initiatives of the jurisdiction and
consideration of what is pragmatically achievable.

For example, a rate change may improve equity and fairness by allowing for more clear cut
assignment of costs to users (criteria number 1 in the list above), but such changes may
dramatically disrupt current arrangements and therefore work against criteria number 3 (stable
rates), and even indirectly (and negatively) impact investment (criteria number 4) by raising
perceived regulatory risks. In order to reconcile opposing effects, regulators in other
jurisdictions have conducted cost-benefit analysis to assess the potential results of rate design
change. Such analyses could be qualitative as well as quantitative, although the latter can be a
substantial effort as it involves approximating market reactions to rate design change and
estimating costs of regulatory burden, forecasting impact of change on transmission utilization,
and pricing of benefits (as well as possible costs) derived from such increased utilization.

\textsuperscript{10} Typically, transmission users reserve access ahead of time and therefore pay a fixed charge ($/kW) irrespective of
actual use. Although some RTOs do a fixed rate per MWh of transmission service used, although the rate itself
is based on forecasted MWh.
It is also important to keep in mind that some of these objectives can be achieved through overall design elements, rather than selection of a specific rate structure. For example, non-discriminatory open access and re-sale of acquired transmission rights allows for users to compete for access and trade the financial implications of that reserved transmission access. Trading then leads to efficient allocation of the existing capacity.

Short of internalizing the rate pancaking problem by way of combining multiple transmitters within a single independently-operated and managed market, cross-jurisdictional agreements and arrangements can reduce rate pancaking and improve not only commodity market outcomes but also raise utilization of the transmission system, which can raise welfare to all consumers (as higher utilization factors can lead to higher marginal costs of transmission (higher congestion charges), which could be used to reduce the transmission providers’ revenue requirement). Indeed, as suggested in Section 1, rate pancaking – to the extent that it is set as a priority - can be reduced under different types of rate formats.

Other objectives are more directly achieved through the selection of rate structures. For example, fixed cost allocation should be structured so that sufficient revenues for full cost recovery are collected, while the potential for distortions of consumption/production decisions is minimized. This is best achieved by fixed charges that are non-bypassable. Such transmission rates will be treated as fixed costs by users and therefore not enter into a rational consumer’s or producer’s consumption or operating decision, since those are based on short run marginal costs. Moreover, the commitment to full cost recovery for transmission owners will yield the right environment for new investment and secure the financial viability of current transmission owners.

At the same time, it is important to keep in mind that rate structures may need to be defined contingent on the particular circumstances of the transmission infrastructure in order to follow the user pays principle. For example, some transmission investments are more likely to have lots of positive externalities and diffuse system-wide benefits and therefore would benefit from a socialization of costs. However, other types of transmission investments are more narrowly focused and therefore, rates for accessing such transmission infrastructure can – and should – be set so that the concretely identified beneficiaries pay (as is the case with connection charges, which we discuss below).

In another example of direct linkages between objective criteria and rate structure choices, under certain circumstances it may be beneficial to consider locationally-differentiated (such as zonal) transmission access charges. For example, to the extent that there are legitimate cost and asset differences between transmission providers (leading to different revenue requirements and demand levels on the transmission capacity), then it is better to have customers pay:

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11 Note that in many organized US power markets, the physical right to the transmission capacity is not assignable or tradeable. Rather, transmission users trade the derivative financial rights to the congestion revenues for that MW of reserved capacity.
locationally-specific charges, in order to avoid cost shifting. Locationally-differentiated access rates can support more efficient generation investment, by reinforcing the signals provided by congestion rates. Locationally-differentiated access rates can also be designed to force a generator to internalize the social costs of its siting decision, and therefore eliminate potential for perverse incentives created by socialized rates. A uniform transmission access tariff will not differentiate between a closely-situated generator to load and a remotely-sited generator. Therefore, such a rate structure has the potential to amplify, rather than reduce, efficiency losses caused by congestion.

Similarly, discriminatory (or differentiated) pricing among customer types (wholesale customers using “through and out” service to trade across jurisdictions and local or domestic customers (native load) taking network service to get delivery of power) can result in a win-win situation where both classes of customers are better off. The basic premise behind such a strategy is that demand for “through and out” transmission services, especially on a short-term basis is highly sensitive to prices because of the nature of such transactions. Indeed, cross-jurisdictional arbitrage opportunities are often times realized not only based on the commodity prices for electricity but also on transmission system charges that a wholesale customer must pay. The cost of short-term transmission service will therefore have a direct impact on whether a “wheel through” transaction is profitable and whether it will be executed.

This “elastic demand” for transmission service means that a decrease in transmission service price could result in an increase in transmission service volume. To the extent there is spare capacity on the system, a rate decrease for “through and out” transmission services would reduce the opportunity costs for cross-border transactions and increase the volume of such trades. So long as the increase in volume exceeds the reduction on rates, the TO is earning more revenues. This revenue earned by the TO in excess of its regulated revenue requirement level could be credited back to the domestic customers. This discriminatory pricing rule is consistent with the Ramsey pricing principle whereby revenues collected from customers with different demand elasticities could be optimized by applying price reductions (increases) inversely proportional to the elasticities.12

With respect to transmission service, the process would go as follows:

(a) Lower the rates on ‘through and out’ transactions, as they are made by customers that have the most elastic demand;
(b) Lower rates should create additional volume.
(c) So long as increased demand offsets the lower tariffs with respect to total revenues, a win/win situation is created.

(d) The revenue requirement for the TO has not changed. Therefore, in response to more revenues from elastic customers (i.e., those making cross-border trades and arbitraging across markets), the rates for (inelastic) native load customers can be reduced.

The following is a stylized example for the province of Ontario of the process described above. Hydro One charges $1/MWh for Export Transmission Service (ETS). For 2007, Hydro One anticipates ETS revenues to total $12 million (about 9.5% of its total revenue requirement), with about 12 TWh of energy transacted. Hydro One treats ETS revenues in a manner consistent with the Board’s view in RP-1999-0044 that export revenue be used to reduce transmission service charges for Network Service customers in Ontario who pay for the network and interconnection facilities through their regulated Network Service rates. As such, any revenues generated by ETS service serves to reduce transmission charges for native load.

Currently, customers using ETS have to pay the transmission tariff charged by Hydro One in Ontario in addition to the ETS charge. This hypothetical example serves to illustrate the impact a reduction of the ETS charge may have on Hydro One’s revenue requirement for native load. Let us assume that, under most circumstances, demand for ETS is elastic and that customers other than native load will make more use of ETS as Hydro One decreases its price for this service, provided there are no other barriers to using the transmission system. Thus, with a rate decrease, Hydro One could obtain greater revenues through an increase in transaction volumes from ETS and could then pass along cost savings to native load as it is required to do as per the OEB’s directive.

For illustrative purposes, we have further assumed that Hydro One faces a linear demand curve for ETS based on an assumed elasticity of -1.5. Given the current rate of $1/MWh we can, thus, estimate the potential impact of reducing the ETS charge to $0.8/MWh on the quantity of ETS demanded and the revenue it would generate under the above assumption of elasticity.

As highlighted in Figure 1, the revenue generated by ETS after the price decrease (see the yellow area) is larger than that amount generated under the current ETS charge (see purple area) by approximately $480 million (a 4% increase).
Though this is a highly stylized example of the possible impact of having a lower charge for ETS on the revenue requirement of native load, it nevertheless illustrates the basic benefits such pricing arrangements could obtain.

Such an outcome represents a Pareto improvement and would be recommended for implementation from an economic perspective, if the circumstances lend themselves to such an outcome. A Pareto improvement represents a welfare improvement that is achieved for one or more customers (industry stakeholders) without hurting any other customer (industry stakeholder). Domestic customers and ‘though and out’ customers would both benefit.
4 Classifying transmission rates

Transmission costs are conventionally recovered through three different charges: connection, access, and usage rates (also sometimes referred to as congestion charges). Why three types of rates? First, given the presence of high fixed investment costs for transmission, transmission rates that were designed to recover all such costs through usage-based tariffs would likely depress usage because the charge per unit of use would be very high. This, in turn, would lead to inefficiencies in consumption. Furthermore, because transmission services are non-excludable, free rider problems (which we discussed in Section 1) can arise, making it difficult to identify beneficiaries and set up fair and efficient charging practices. Usage rates purely based on marginal cost pricing\(^\text{13}\) would also jeopardize fixed cost recovery for the transmission provider. Under-provision of the service can arise.

In summary, in order to meet the critical objectives of an efficient transmission rate-setting and to overcome the economic hurdles of externalities and free rider problems, policymakers – with the support of welfare economists\(^\text{14}\) - have commonly implemented multi-part tariffs for transmission. An efficient pricing mechanism would therefore be comprised of:

1. a transmission connection charge to recover directly attributable long-run costs such as connecting a generator to the transmission system

2. a transmission usage charge to recover the short-term marginal cost of transmission, notably congestion and losses.

3. a transmission access charge to essentially recover those fixed costs that have not been recovered under connection or usage charges.

Under such a system the TO is assured of recovering the fixed costs associated with the transmission system and those associated with new connections and expansions. Furthermore, the TO also recoups the costs of marginal use of the system. The final consumer also typically benefits from this type of arrangement by being allocated its fair share of the fixed transmission costs and is only charge for its marginal use of the system if its transaction causes congestion on the network.

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\(^{13}\) Marginal cost pricing involves pricing of the product or service based on the incremental costs of producing one extra unit of the product or service; in the case of transmission, this is analogous to one extra MW of capacity on which to transmit electricity.

\(^{14}\) Harold Hotelling proposed in the 1938 presidential address to the Econometric Society that it would be welfare enhancing to follow a two-part tariff (consisting of a fixed fee and a marginal or usage-based fee) for pricing products and services produced by natural monopolies, in contrast to the marginal cost pricing equilibrium that would arise in workable markets for other “normal” goods and services. See “The General Welfare in Relation to Problems of Taxation and of Railway and Utility Rates”, 1938, Econometrica.
Transmission access and congestion charges can be viewed as the practical analogy of the two-part tariff concept in the current, deregulated market environment. They are both intended to pay for the existing transmission system. As we discuss in the companion Chapter containing case studies, not all markets have distinct transmission usage charges, as these types of charges will only arise under particular market designs. For example, in many US markets, usage charges based on marginal cost pricing principles are effectively the transmission congestion charges. Transmission congestion charges may be explicit and locationally-specific under certain wholesale market design. The primary purpose of such congestion charges is to determine how to allocate scarce transmission capacity and therefore they are set by reference to the commodity being transported. However, even in those markets without an explicit congestion charge, customers still pay the costs congestion, for example through uplift charges that are bundled with other rates.

It is important to keep in mind that from an operational perspective transmission access and transmission usage are distinct. Transmission access is typically considered in terms of reserving capacity while usage involves the actual transport of electricity. The marginal value of transmission is priced with usage charges, because it is based on the users’ perceived value of having one additional MW of capacity to transport and sell electricity. A positive marginal value of transmission will arise only when the transmission capacity is constrained; therefore, the marginal value is measured on the basis of the economic value of the congestion that is relieved (e.g., the difference in commodity prices of electricity).

Because transmission usage is a function of the costs of electricity production rather than the costs of building and maintaining the transmission asset, a disconnect is likely to arise between revenues a transmission provider can earn on a forward basis through congestion charges and the revenue requirement for the transmission provider based on historical costs of investment (as described in the example above). Therefore, transmission access charges are created to “fill” the gap. Indeed, in practice, transmission access charges are determined first, because it is relatively easy to establish the revenue requirement once the infrastructure is commissioned and the capital costs incurred. Then revenues generated by the sale of congestion-related instruments, which provide a hedge on the cost of usage for the buyers of such instruments, are used to reduce the access charges or are otherwise credited back to transmission users.

Illustrative example of different types of transmission rates:

<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
</tr>
</thead>
<tbody>
<tr>
<td>1,500,000 kW</td>
<td></td>
</tr>
</tbody>
</table>

There exists transmission line AB, with a capacity of 1,500,000 kW and levelized capital cost and O&M (revenue requirement) and $25 million per year. The transmission line is not congested for majority of hours, but during periods of congestion (20% of hours in a year), electricity prices at area B are higher than area A by $2/MWh.

Transmission access charge = $16.67/kW per year

\[
\frac{25,000,000}{1,500,000 \text{ kW}} = \frac{16.67\text{$/kW}}{}
\]

Effective transmission usage charge = $3.50/kW per year

\[
\frac{\$2 \text{ per MWh} \times 1,500 \text{ MW} \times 8760 \text{ hours} \times 20\%}{1,500,000 \text{ kW}} = \frac{3.50\text{$/kW}}{}
\]
Connection charges are slightly different from the other two types of charges because they are associated with a specific class of transmission infrastructure. Connection charges are set up to remunerate the capital costs of interconnecting a (new) transmission user, such as a new generator or new a customer (load) to the pre-existing network. The fundamental question regarding connection charges focuses on determining who initially pays for the cost of new connections and how that cost will be allocated among the various involved parties, notably the transmission company, the transmission service customers, and the generator or load that is connecting to the grid.

Although the focus of this Chapter is on transmission access charges, we summarize below the basic elements of connection charges, since they are typically formulated as an (additional) access charge. The issues that arise with setting of connection charges also directly relate to the economic problems we discussed in Section 1; therefore, are relevant to the question of transmission access and rate design. We then move on to discuss congestion (transmission usage) charges and transmission access charges.

4.1 Connection charges

Transmission connection charges are needed to recover the investment cost that occurs when new generators or load connects to the transmission grid. As such, connection charges are typically utilized in situations where the direct beneficiary (transmission user) is presumably easy to identify. Nonetheless, there are some “gray areas” with respect to beneficiary assignment even with interconnection, since an additional generator or load can change the operating dynamics of the entire system. Therefore, the principle debate in rate setting of connection charges is whether the interconnected generator or load is required to pay solely for the equipment that connects him to the grid or for additional upgrades on the grid that may be necessary to better incorporate the new connection. In industry circles, the latter concept is referred to as a “deep” charging principle (because the consumer may pay for distant system upgrades), while the former concept is referred to as a “shallow” charging basis (because, in this case, the consumer pays for only the costs of immediate interconnection-related infrastructure).

In economic terms, the issue of deep versus shallow connection rate structures relates to the economic problem of a public good and positive externalities discussed in Section 1. On the basis of cost causation objectives, connection charges should aim to assure that those entities causing an extra cost to the system are held responsible for paying the extra cost through a connection charge. In essence, the connection charge should enable the transmission owner to recover the costs (capital and operating) that are directly attributable to a particular user. Thus, generators whose locations reduce transmission congestion might be charged differently from those located in an area which causes congestion to increase.
It is important to consider that the cost allocation of connections to the transmission grid can also affect investment decisions and these should be consistent with the policy objectives envisioned by the regulator. For example, minimizing the allocation of new connection costs to generators would serve as an incentive to new generators. Connection charges can also impact broader policy objective destined to encourage new generation and transmission. For example, generators can be incentivized to build new plants by being charged shallow connection charges.\(^{15}\)

A shallow connection charge will help reduce the development and construction costs of new plants as some of the costs to connect to the network are borne by all transmission system users through the other transmission access charges. Such policies also serve to incentivize new transmission build as the transmission company is assured of recovering the network expansion costs it incurs with every new connection through its rate filings.

On the other hand, some may also justifiably argue that a shallow connection policy can impede transmission investment that would otherwise directly compete with generation. A further disadvantage of shallow connection charge is that it may result in an unnecessary increase in the cost of the network due to siting decisions made on the narrow basis of the least cost for the generator rather than for the system as a whole. Such a practice could be construed as contrary to the regulated entities’ objective to safeguard the interest of consumers in assuring them fair and reasonable rates. An example of such an event would be a coal-fired generator siting its

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\(^{15}\) Additionally, connection costs can be structured in such a way that they favor certain type of new generation connecting to the grid, such as renewable energy (for example, by applying “shallow” connection policies to such generators and “deep” charging policies to others).
plant near a coal mine which is several hundred kilometers away from any network infrastructure. With a shallow connection policy, the generator would reap the benefits of low fuel supply costs in addition to not paying the full costs of the network connection. On the other hand, the same example with a deep connection policy could lead the generator to site its plant closer to the existing network infrastructure thus choosing to pay higher fuel supply costs. While these are two extreme scenarios, they help illustrate the potential impact range such a policy determination may have.

Although the above coal-fired example is illustrative of the potential inefficiencies that could result from shallow connection charges, there is somewhat limited potential for such outcomes in Ontario. Therefore, the ease of administration of a ‘shallow’ connection charge (which is the current policy in Ontario) is likely to outweigh the potential benefits of avoiding inefficient investment decisions. Furthermore, it is also important to keep in mind that connection costs can sometimes be re-assigned if usage after the connection is different than anticipated. For example, refunds to generators who incurred the costs associated with the connection for their generation site occurred when that connection was subsequently used by other generators.

4.2 Congestion charges

As described in Section 1, transmission services are not pure public goods because they are finite: the level of capacity is fixed once transmission is built. As usage levels rise to maximum capacity levels, transmission service will appear to be a scarce resource. In transmission systems with many users, congestion is not caused uniformly by all consumers and generators. In the longer term, generators and consumers make location decisions which impact congestion by either increasing or decreasing competition for transmission capacity. The presence of congestion requires some method of allocation of the scarce resource in the short term, as well as a method for incentivizing more efficient locational decisions in the longer term.

Consistent with social welfare optimization concepts from economics, the preferred approach is to prioritize allocation based on value. On this basis, available capacity should go to those customers that value it most. This requires a system that establishes the value of transmission. Given the presence of wholesale power markets, a system operator can measure the impact of inadequate transmission – congestion will be reflected either explicitly or implicitly in commodity prices. The critical issue for policymakers is to choose how such costs are allocated. Congestion charges can be socialized through uplift payments by all users or could be

\[16\] For example, a generator located far from an end-user, connected by transmission lines that are heavily used, would be responsible for more congestion than a generator located close to load, and the distant generator should pay more to account for the greater congestion burden on the system. Users who increase congestion are creating a public “bad” (or negative externality), potentially imposing a cost on other users.
differentiated by user under an administrated or market pricing process. We briefly discuss each approach below by reference to actual market application, here relevant.

**Socialized congestion charges**

Ontario currently socializes all costs of internal congestion, as do many other markets around the world, and therefore consumers pay a uniform congestion cost component within rates. The most often cited disadvantage of a socialized approach to congestion charges (which is equivalent to a postage stamp rate for access) is that it biases investment decisions. Similarly to the potential bias for new investment described in the coal example illustrating the possible effect of the “shallow” connection charge concept, a socialized approach for congestion charges can lead to situations where generators’ siting decisions are producing negative externalities by increasing congestion on the system, to the dis-benefit of other users.

**Administrative process for setting locational charges: estimating the long run marginal cost of transmission**

National Grid (NGC), the transmission provider in the England & Wales market, applies an administrative process to determine sculpted zonal long term cost-based transmission rates under its investment cost-related pricing (ICRP) model. NGC uses incremental capital cost models of the transmission network to estimate the extra transmission investment costs (combining capital costs and usage/congestion charges) that would be needed to meet a 1MW increase in generation or demand at particular locations – indeed, between specific nodes – along the network. While the NGC model is nodal in nature, its outputs are grouped on a zonal basis for simplicity and stability in tariffs. In summary, the zonal tariffs are based on

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17 NGC historically used a transport-based model to derive the long run marginal costs; the model looked as overall transfer capacities between nodes/zones, but did not monitor any other transmission elements. There are two alternatives for improving on the transport model. First, scale of investment could be considered (and therefore the model would not simply look at the next 1 MW of load), similar to the transport model used by Transco (the gas transmission company in the UK). This would more realistically represent the lumpy nature of investment; however, some subjective input would be required regarding the size of power increment and the discrete “lumps” of investment to be used in the model. Another improvement on the transport model would be to include more detailed representations of the network. A DC load flow model would share the basics of the ICRP model, but would, in addition, introduce real circuit parameters. In effect, this provides a more realistic representation of flows. A DC load flow model may give rise to greater nodal differentials than an ICRP transport model. However, the increased number of inputs makes this model slightly more complicated to run compared to the basic ICRP model. A further improvement on the ICRP and the DC load flow models would be the incorporation of system security constraints by modeling several different contingencies. Such a model would use the circuit ratings as an input, and take spare capacity on circuits into account. With the additional incorporation of security constraints, the nodal differentials obtained in tariffs calculated using this model would be more pronounced. The choice of relevant contingencies to be modeled makes the model more subjective. Also, increased number of model runs and outputs might make the security model the most complex to run.
modeled expectations of long run marginal cost of transmission. The biggest criticisms of the ICRP process generally stem from the assumptions made by NGC in the modeling of investment costs. Some opponents of the ICRP scheme have also criticized the tariff trends – noting that they have not been high enough to effectively enter into generation investment siting decisions, as compared to other costs and barriers to investment.

**Market pricing of transmission congestion: through LMP systems**

Allocation based on market forces is achieved through what is commonly referred to as locational marginal pricing (LMP) schemes. LMP systems establish a very specific price signal as to scarcity of capacity across all locations (at the zonal or even granular nodal level). In so doing, an LMP system internalizes the costs of congestion for each and every transmission user in the short run and therefore eliminates the potential for negative externalities. Policymakers can then require each user of the system to bear the cost for the congestion they create (or reward users for decisions that relieve congestion). Indeed, congestion charges under an LMP market design are an explicit component of the commodity price, rather than a stand-alone transmission tariff.\(^{18}\) Opponents of LMP pricing and locationally-differentiated congestion charges typically cite the issue of the practical cost of implementing LMP markets, which involves rewriting market rules, implementing new software and operating practices, and generally changing current market arrangements (which market participants may find disturbing and may lead to near term delays in investment initiatives as the market assimilates to the new environment).

**4.3 Access charges**

In contrast to the real time derived value of congestion charges, the access charge pays for the cost of maintaining and operating the transmission, as well as allowing transmission owners to recover a return on their investment. Connection charges and congestion charges, however designed, will not cover the full costs of transmission service primarily because of the sunk costs of investment in the existing infrastructure are very large and, unless a transmission path or interface is highly congested (and there are substantial differences in generation costs), the congestion or usage charge will be small. In other words, the need for an access charge arises because transmission providers cannot be assured of cost recovery through usage-based (congestion) charges (unless those usage charges include investment costs, as in the case of NGC’s administrative ICRP method).

In order to complement competitive markets and provide an opportunity for third parties to access the transmission system, access charges should be designed to allow for open access to the network by eligible third parties with a clear, transparent system defining access rules and pricing. Access rules typically define the allocation of capacity, while pricing is commonly

\(^{18}\) Financial transmission rights (FTRs) then provide an opportunity for users to hedge those congestion costs.
based on a cost of service revenue requirement. Therefore, once O&M and capital costs are identified, it is only a matter of how they are allocated among customers. This gives rise to different types of access charges. Access charges can be socialized or specific to a particular service area or transmission investment, similarly to the alternatives available for congestion charges. In the US, it is also common for transmission reservations to be for short-term and long-term durations, as well as for firm or non-firm basis. We discuss the different options of allocation further below, after we first consider the question of calculation and payment.

**How are access charges calculated?**

Access charges are based on revenue requirements, and are adjusted on a going forward basis once additional infrastructure is built whose costs are not otherwise being recovered through connection charges. In order to avoid severe rate shock given the lumpiness of investment, transmission investment costs are typically depreciated over very long periods of time (and, in some instances, deferral accounts may be additionally used). Access charges can be denominated in terms of a capacity (i.e., a demand charge ($/kW)) or based on volume of energy (i.e., a volumetric charges ($/MWh)). The demand charge is most common approach, especially since a volumetric charge based on prospective usage is likely to be excessive. Transmission access rates based on a volumetric measure are less practical. It is hard to estimate ex ante the level of usage and even harder to identify beneficiaries. In addition, volumetric charges are more likely to vary year-on-year, frustrating the objective criteria for ‘predictable’ costs. Indeed, given the unique aspects of the electricity sector (like the need for instantaneous coordination of supply and demand), transmission is typically built to satisfy peak demand and a margin on top of that to insure against contingencies. Therefore, the concept of a demand charge is most appropriate since it is based on maximum capacity available to meet such conditions.

In US markets, as well as in many other jurisdictions, transmission access is commonly sold for one-year periods, as well as shorter intervals. Given the demand charge formulation and the premise of the revenue requirement, the difference in rates is simply a function of how many hours are covered by the transmission reservation. Therefore, a transmission access charge of $12/kW per year is the same as $1/kW per month and a $32.88/MW per day (assuming 365 days) and $1.37/MW per hour (assuming 8760 hours).

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19 In the case where all transmission costs are not socialized across all customers, one of the complexities of transmission access rate design is determine how to allocate charges for parts of the network that are shared. This requires identification of cost causation of beneficiaries which can be a difficult task given the physics of electricity systems. One common approach, which is the simplest approximation of cost causation, is to require that allocation amongst consumer is done on the basis of coincident peak demand. Some jurisdictions use more complex power flow models to establish usage of common resources and identify beneficiaries.
Who pays access charges?

Final customers (by way of load serving entities paying this cost directly or having it passed on from their wholesale suppliers) are typically assigned the obligation to pay access charges, since they are the ultimate beneficiaries of transmission. However, in some markets (most notably, in the United Kingdom, Argentina, Sweden, and Norway) generators may also be obligated to pay some portion of access charges. The argument in favor of charging generators a portion of the fixed costs of investment is that such a policy creates awareness about transmission costs (even if the generator passes on these costs in its sale of electricity to the buyer) and may encourage efficient use of the system.

How are transmission access costs allocated?

There are two basic formulations of access rates: uniform tariffs and locationally-differentiated tariffs. Uniform transmission access rates are also referred to as postage stamp rates because all customers, regardless of their location, pay the same rate to transport electricity, regardless of distance (similar to the basic pricing of first class mail).

There are a number of advantages of uniform tariffs. Because of its simplicity, such a rate scheme is typically relatively easy to administer. Furthermore, a uniform tariff generally means that sunk costs are being spread over a large volume of users, and therefore large incremental investments produce smaller rate shocks from the perspective of the consumer. In addition, some argue that this rate scheme is especially valid from an economic perspective given the public good nature of transmission: all customers reap benefits of transmission and therefore should equally share in paying for it. Given the practical consideration that it is in fact difficult to measure the relative benefit accruing to beneficiaries, a single uniform transmission access rate is very common feature in power markets worldwide.

On the other hand, to the extent that there are potentially diverse benefits across users or diverse costs of investment across areas, a postage stamp rate does not strictly adhere to cost causation and beneficiary pays principles. The alternatives to a uniform rate for access charges can broadly be grouped into two categories: zonal rates and distance-based rates.

Zonal rates are common. In US markets, zonal rates are also referred to as license-based rates. The use of zonal rates is justified on the basis of legitimately different cost structures and asset compositions for transmission providers in a given market. In other words, zonal rates may more accurately reflect cost causation principles and, depending on who is charged, also reinforce investment signals. However, zonal rates are more administratively intensive as they may involve accounting mechanisms (to re-distribute revenues from transmission to ensure full cost recovery of all transmission providers in the system) and use of engineering models, as in the case of NGC’s ICRP or the power flow modeling that is done in certain other markets to establish benefits-driven distribution of rates.
The existence of zonal transmission access tariffs does not preclude elimination of pancaking. For example, as discussed in more detail in the case study Chapter, PJM has been successful at using license plate tariffs for transmission access, but has also eliminated rate pancaking in its jurisdiction (and has negotiated elimination of rate pancaking with its neighboring market to the West, operated by Midwest ISO). PJM had implemented license plate tariffs in recognition of the fact that its market is composed of a number of transmission networks, each with very different revenue requirements and loads, because of the age and type of asset holdings. In order to achieve equity and limit cost shifting, PJM made a decision to retain the specific rates of each transmission provider. Then, in order to avoid pancaking, PJM stipulated in its Open Access Transmission Tariff (which was approved by FERC), that customers pay on the basis of the zone where the energy is withdrawn – i.e., location of load). Therefore a supplier transporting power across multiple transmission system would only pay one charge, based on final destination.

Distance-based rates, also referred to as the “megawatt-mile” cost allocation method, have been proposed but never truly implemented. The argument in favor of such an approach is based on the premise that access rates should be tied to customers’ intended usage and that the attributable benefits and costs are related to distance. Therefore, this method was very complicated, requiring modeling of power flows, and frequent recalculation as transactions in the system change the nature of flows. The complication was just one of many sighted disadvantages. Other criticisms of distance-based rates include rate instability and economic concerns about the underlying premise. There have been valid arguments made that costs and benefits of transmission are not robustly correlated with network miles. In addition, the nature of the allocation design results in greater variability in the rate (so less rate stability). For example, changes to postage stamp rates or zonal rates for transmission service area are driven only by changes to the revenue requirements of the transmission owner(s) or changes in carrying capacity of the line or annual peak load, but with mileage based tariffs, there is a lot more complexity because one needs to consider power flows and changes in system dynamics. The reduced rate stability is a major concern for transmission users.

**How does firmness relate to access?**

In order to allow for optimization of usage on transmission systems, a common feature of North American power markets is to distinguish between firm and non-firm service. Most network service within an organized, ISO-coordinated market is firm; therefore, the concept of non-firm service is more commonly applied in transactions that cross markets, or in jurisdictions with no central ISO (like the Pacific Northwest).

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20 For example, both SPP and MAPP had one time or another proposed the use of such methods.
NERC Transmission Loading Relief Procedures:
If an operating limit has been breached, System Operators must follow the following sequential procedures until transmission equipment loading is within permissible operating limits:

- level 1 – notify security coordinators of potential operating security limit violations
- level 2a – hold interchange transactions at current levels to prevent operating security limit violations
- level 2b – reallocate firm transmission service
- level 2c – reallocate no-firm transmission service
- level 3 – curtail interchange transactions served by non-firm transmission service arrangements
- level 4 - reconfigure transmission and redispatch generation
- level 5a – curtail interchange transactions using firm transmission service to mitigate an operating limit violation
- level 5b - reallocate transmission service by curtailing interchange transactions using firm service on a pro rata basis to allow additional interchange transactions using firm transmission service
- level 6 – implement emergency procedures

Curtailment of transactions follows the FERC pro forma tariff with regard to Transmission Service priorities:

- Priority 1. Service over secondary receipt and delivery points
- Priority 2. Hourly Service
- Priority 3. Daily Service
- Priority 4. Weekly Service
- Priority 5. Monthly Service
- Priority 6. Non-firm imports for native load and network customers from sources not designated as network resources
- Priority 7. Firm Service

Source: [http://www.nerc.com/~filez/nerc_filings_ferc_tlr.html](http://www.nerc.com/~filez/nerc_filings_ferc_tlr.html)

4.4 Linkage between congestion charges and access charges

Although transmission access charges are not part of wholesale market prices (which reflect congestion charges), there are nevertheless linkages between transmission access charges and commodity market dynamics. First of all, the design of transmission access charges (including policies for connection charges) can effect investment decisions of generation and therefore impact the functioning of the wholesale market. Transmission access policies that encourage transmission investment also directly benefit wholesale markets, by broadening the opportunity for trading and cost minimization. The style of transmission access charge can also effect the
level of trading and therefore impact welfare of consumers (for example, license-based tariffs that are high in a particular location can reduce the motivation for transactions in that location by dampening the economics for trading). These linkages exist regardless of wholesale market design.

In LMP markets, however, there is an additional direct link between access charges and congestion charges, in recognition of the fact that congestion revenues are meant to remunerate transmission operators for their well-placed assets. It is standard protocol for LMP market design to include financial transmission rights (FTRs). FTRs are sold to transmission users, allowing them to hedge the congestion cost component of their wholesale market transactions. The initial auction of FTRs raises revenues. Although the allocation of these revenues may differ across markets, the end result is that these funds reduce the effective transmission access charge: in some markets, transmission owners receive these revenues to offset their fixed costs and the transmission access charge is adjusted; in other markets, the revenues are allocated back to transmission users.

The biggest issue with FTRs is that they are a short-term signal that is not wholly compatible with getting long-range transmission investment built. The value of short-term FTRs is unlikely to sufficiently fund the fixed costs of new transmission, as we discussed earlier in this Chapter. Furthermore, the economic incentive signals observed through LMP price differences is dwarfed by the operational issues to getting new transmission sited and built in certain high-congestion corridors (indeed, many currently congestion areas become so because of lack of new generation and transmission investment).

This dynamic is also implicit in the NGC ICRP model, since the transmission charges that emerge from that rate processes consolidate both the embedded investment costs and congestion charges into one measure of incremental cost and the final tariff.
5 Concluding remarks

The choice of locational differentiation is, as the name implies, the choice of how “locational” the transmission charges should be. For an electricity transmission charges, there are effectively three options: to charge for transmission on a flat (uniform) basis, to establish a zonal basis, or to move as far as nodal pricing (for congestion). Figure 2 below shows these three options, and the associated issues and tradeoffs.

<table>
<thead>
<tr>
<th>Flat</th>
<th>Zonal</th>
<th>Nodal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Increasing complexity</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Increasing efficiency of locational decisions</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Increasing reflection of costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Increasing impact of other users’ actions</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Increasing stability</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Increasing predictability</td>
<td></td>
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</tbody>
</table>

On the other hand, the choice of temporal differentiation is the choice of over what period the transmission “product / service” should be defined and, as such, priced. For an electricity transmission network tariffs, the alternatives range from hourly (possibly even shorter periods) for usage rates to annual (for access and connection charges), along with different flavors of “firmness” possible. Access charges based on volumetric metric (rather than the more common demand metric) are likely to require a more frequent schedule, so that tariffs properly reflect shifts in demand growth and utilization levers. On the other hand, one could envisage a system of transmission charges with an even longer time horizon than a year, especially if they are linked to stable revenue requirements. Figure 3 below shows the degree of temporal differentiation in charges.
In our view, the main trade-off (along both locational and temporal scales) is one between more “granular” cost-reflection versus predictability and stability. It is also reasonable to assume that the more complex the approach is (i.e., a nodal market pricing framework), the more costly it would be. Thus the expected benefits from increased cost reflection via short-run approaches might easily be exceeded by the expected costs of implementing such approach.

Across North America, there is evidence of different types of access charges: some markets rely on postage stamp rates for system-wide or network service, while others use license plate rates (zonal). It is important to note that both approaches can accommodate removal of internal rate pancaking across multiple transmission service providers’ franchise areas in the market. In addition, as we discuss further in the case study chapter, there have been different approaches used within one market. For example, FERC recently approved the use of a postage stamp rate for all high-voltage new transmission in PJM, because its benefits are expected to be accrue to all customers within the PJM footprint. In the same Order, FERC reaffirmed its previous decision and retained license plate rates of existing transmission infrastructure. Similarly, in New England, local service (using lower voltage network elements) is charged on the basis of zonal rates (i.e., each transmission provider’s own rate schedule), while network service on “pooled” network resources is based on a single rate, regardless of distance traversed or the number of transmission service territories crossed, because such facilities (and therefore the network

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21 In the terms of reference, OEB posed the question of whether there has been any concern that long distance transmission is being subsidized. One interpretation of FERC’s recent decisions (authorizing a postage stamp rate for new high voltage transmission in PJM) suggests that the Federal US regulator believes the answer is “no” and that there are yet still more opportunities from larger markets and potential benefits in terms of expanding economies of scale in trading and increased competition. However, this position at FERC is as much a policy decision as it is an economic one. FERC is the foremost champion of wholesale markets and may naturally favor policies that result in the integration of smaller markets into larger marketplaces, without weighing the marginal effect of its transmission cost allocation policies on the types of transmission investment.
service) is considered to be benefiting all users of the system. Different access charges, therefore, can be formulated to meet the unique conditions of a market: with rates differentiated by location, type of service (firm versus non-firm), customer type, existing versus new infrastructure, lower versus higher voltage assets.

As discussed in this Chapter and in the subsequent Chapter (Chapter 3), a postage stamp (uniform) access rate is justified if the transmission service can be shown to deliver benefits to transmission users on the system and if the transmission is characterized by strong positive externalities. License plate or zonal access rates are more optimal if there are significant and legitimate differences in rate base for one area (or group of customers) versus another, and the transmission’s beneficial effects can be limited to a particular area or group of users. However, the costs of implementing a locationally differentiated rate approach also need to be considered. It may, in fact, be easier (and more consistent with economic considerations) to design access rates based on non-geographical features, such as existing versus new transmission, high voltage versus low voltage transmission local versus ‘through and out’ service.
Chapter 3: Case Studies: Transmission Access Charging Principles across key North American power markets
Chapter 3: Case Studies: Transmission Access Charging
Principles across key North American power markets

prepared for Ontario Energy Board

November 19, 2007

London Economics International LLC (LEI) was commissioned by the Ontario Energy Board (OEB) to review the treatment of access charges in various North American jurisdictions. As such, this Chapter reviews the transmission access charges for Alberta, the California ISO, the Midwest ISO, the New England ISO, the New York ISO and PJM which have all adopted, with the exception of Alberta and the New England ISO, a zonal rate design. However, many of these markets are transitioning or are considering transitioning to a postage stamp rate in the future.

The case study analysis highlights that the choice of transmission access tariff design has been driven by policymaking issues endemic to the individual jurisdictions as much as broad economic arguments. For example, zonal tariffs are to some degree a legacy of the preceding market structure, where each transmission provider had its own independent charge rate, and moving to a single rate would have severely disturbed existing arrangements and caused cost shifting among consumers. However, improvements have been made over legacy regimes, as all markets studied have been able to eliminate rate pancaking.

The experience of other markets provides some important considerations for Ontario as policymakers consider whether or not to modify the current transmission access charging policy. First and foremost the postage stamp approach Ontario has adopted has been highlighted in many of the jurisdictions studied as the preferred rate design. Many of the US markets are in fact moving towards postage stamp rates for transmission. As such the experience of other North American jurisdictions suggests that Ontario can remain with its current postage stamp rate design. The province could however potentially explore setting up transmission tariffs which are differentiated by type of transmission service or customer. Ontario could consider differentiating its rates by logical asset class: for example, authorize a set of geographically distinct rates for the existing networks (based on legitimate cost differences) and set up a postage stamp charging policy for (new) transmission investment that unambiguously provides benefits to consumers province-wide, as is the case in PJM for instance. Such a rate design would be economically rational and applicable in Ontario to the extent that new transmission projects were high voltage backbone projects that benefit all users. This approach would also be fairly easy to administer after the existing system tariffs are developed. It would also alleviate the problem of incorporating lumpy investment into existing pooled tariffs, and further allow for more accurate allocation of local costs differentials, when those are driven by different load growth. Another option is to differentiate rates by customer class, for example internal consumers that are using the equivalent of network service versus wholesale consumers that are using through and out services. This may be a difficult proposition from a political perspective, and at the minimum, would require careful analysis to assess what optimal tariff levels would need to be in order to ensure intended Pareto improvements.
1 Executive summary

In Ontario, the Independent Electricity System Operator (IESO) charges transmission users a “postage stamp” tariff for transmission access, although there are six transmission providers licensed and regulated by the Ontario Energy Board (OEB). Since 2002, all transmission users pay, regardless of their location, a uniform charge for accessing transmission in the province. The choice of a uniform rate was based primarily on the goal of eliminating rate pancake in the province, so that customers with transactions that utilize more than one transmission provider’s network within Ontario would effectively pay one charge.

As part of an economic review of the efficacy of a postage stamp approach in Ontario, this Chapter considers the transmission access tariff design in various North American jurisdictions. As is further described in the body of this Chapter, there is no “one size fits all” approach to transmission access charges. The market design choices for transmission access are made as a result of a host of factors, many of which stem from local issues and considerations, notably the differences in the underlying ratebase for transmission provider(s), the wholesale market structure, and the overall geographic area. PJM, for instance, currently charges “license-plate” rates for transmission access services, which are a form of zonal tariffs. Under this rate design, each customer pays a rate based on their local network provider’s ratebase, but can then freely use the entire network. The exception to this zonal pricing approach in PJM is the recently FERC-approved socialized cost allocation process for new transmission facilities rated at 500 kV and higher. Customers across all of PJM will be charged on a uniform basis (i.e., “postage stamp” approach) for these new assets, because of the expected system-wide benefits of such transmission. As PJM and MISO move towards further harmonization of their rate design, this issue will be revisited. However, the effective application of a postage stamp concept to new transmission will mean that over time, there will already be a transition process towards a uniform tariff (given the continued depreciation of the existing transmission assets, which are underlying the license plate charges).

Figure 4 provides a summary of the key ‘market’ characteristics of the six jurisdictions studied in this Chapter, as compared to Ontario. As is further detailed in the individual jurisdictional sections below, the case studies cover a diverse pool of markets, for example those with and without LMP wholesale market structure, markets with small and large transmission networks and small and large geographic footprints.

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22 The uniform transmission rates however only apply to the four transmission operators, the other two licensed transmission providers being solely transmission owners.
Figure 4. Overview of case study jurisdictions

<table>
<thead>
<tr>
<th>Jurisdiction</th>
<th>Peak load (MW)</th>
<th>ICAP (MW)</th>
<th>Transmission (km)</th>
<th>Population served</th>
<th>Jurisdictions covered</th>
<th>Transmission access charge</th>
<th>Wholesale transaction ($ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AESO</td>
<td>9,661</td>
<td>11,497</td>
<td>21,100</td>
<td>3,400,000</td>
<td>AB</td>
<td>Postage stamp</td>
<td>3,970</td>
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<td>CAISO</td>
<td>45,431</td>
<td>54,500</td>
<td>41,000</td>
<td>30,000,000</td>
<td>CA</td>
<td>All new transmission flows through postage stamp component</td>
<td>2,450</td>
</tr>
<tr>
<td>MISO</td>
<td>136,520</td>
<td>162,981</td>
<td>150,600</td>
<td>40,000,000</td>
<td>15 states + 1 province</td>
<td>Zonal but transitioning to postage stamp</td>
<td>24,200</td>
</tr>
<tr>
<td>New England ISO</td>
<td>28,127</td>
<td>33,477</td>
<td>12,900</td>
<td>14,000,000</td>
<td>6 states</td>
<td>Zonal</td>
<td>9,000</td>
</tr>
<tr>
<td>New York ISO</td>
<td>33,939</td>
<td>38,958</td>
<td>17,700</td>
<td>19,200,000</td>
<td>NY</td>
<td>Zonal</td>
<td>8,610</td>
</tr>
<tr>
<td>PJM</td>
<td>144,644</td>
<td>164,634</td>
<td>90,200</td>
<td>54,000,000</td>
<td>13 states + DC</td>
<td>Zonal for existing transmission and postage stamp for new 500 kV transmission</td>
<td>20,100</td>
</tr>
<tr>
<td>Ontario</td>
<td>27,005</td>
<td>31,000</td>
<td>29,000</td>
<td>12,690,000</td>
<td>ON</td>
<td>Postage stamp</td>
<td>9,890</td>
</tr>
</tbody>
</table>

In summary,

- Alberta’s transmission access pricing system is based on a postage-stamp design where all loads pay the same price for transmission services no matter the origination (injection point) or destination (withdrawal point) of the energy. Similarly, costs of transmission network expansion (often in response to congestion found on the network) are borne by customers on a uniform basis.

- The CAISO’s license-plate rate design is transitioning into a postage-stamp rate (and that transition should be complete by 2011 for current transmission owners). The current transmission access charge is calculated on a blended basis of (a) license-plate (zonal) rate for three principal areas (which equate roughly with the franchise areas of the three major transmission providers) and (b) a grid-wide rate component. Over time, the license-plate rates are going to be phased out. In order to limit cost shifting and rate shock, the contributing proportion of the zonal license-plate rate is reduced by 10% annually, until the year 2011 when all customers will have transitioned to a grid-wide (postage stamp) tariff. Under the current wholesale market design, which is basically zonal, revenues collected from the sale of interzonal firm transmission rights, which hedge against congestion costs by allocating physical priority rights to transmission service, are used to reduce transmission access charges. Under the future nodal market design, financial rights would replace the current physical rights and the auction proceeds from the sale of financial congestion revenue rights are expected to be allocated to reduce access charges.

- The Midwest ISO currently employs a license-plate rate design for transmission access services, the rationale for which is similar to that of California and PJM (described below) – namely to prevent cost shifting and rate shock. In February 2008, MISO is slated to harmonize their transmission rate design with that of PJM. Although this more “uniform” rate design is presently under the discussion, initial proposals have targeted a postage stamp rate concept. The wholesale market in MISO uses LMPs to account for congestion and losses on its system. Notably, revenues generated by the revenues collected from the sale of Financial Transmission Rights (FTRs) are credited back to transmission owners and are then used to reduce the access charges.

- ISO New England (ISO-NE) administers a uniform (postage stamp) transmission access charge. Furthermore, Auction Revenue Receipts from the sale of FTRs are allocated by the ISO directly to customers (via load serving entities) to reduce congestion costs (in addition, some revenues from the sale of FTRs go to fund upgrades to the transmission system to the extent that those qualified upgrades were not part of the pooled tariff). Therefore, ISO New England’s FTR revenue allocation mechanism allows for more targeted rate reductions: only load within New England benefits from the offset created by the FTRs, transmission access charges for external customers (for example, those using through and out service) are not affected.
• The New York ISO’s (NYISO) transmission access is provided through a licensed-plate tariff where each transmission owner has a different tariff for the use of their transmission network. The tariff is derived based on the transmission owners’ revenue requirements and is adjusted annually by incorporating the revenues generated from the sale of Transmission Congestion Contracts (TCCs), which are then used by market participants to hedge the costs of congestion (similar to FTRs in other jurisdictions). Thus, there are linkages in this market, as in CAISO, MISO, New England ISO, and PJM, between congestion costs in the wholesale market and the transmission access tariff.

• PJM charges license-plate rates for transmission access services for existing transmission. Recently, FERC approved socializations of costs for new transmission facilities (500 kV and higher), which will result in a postage tariff component. Customers across all of PJM will be charged on a uniform basis for these new assets, because of the expected system-wide benefits of such transmission facilities. In PJM, transmission customers receive Annual Revenue Rights (ARRs) which entitles them to receive proceeds from FTR auctions in proportion to the economic amount of ARRs they hold, similarly to what is done in New York and (to some degree) in New England. In addition, revenues from non-firm point-to-point transmission services are distributed to network and firm point-to-point transmission consumers as a way to avoid any revenue over-recovery.

Although the case studies, alone, do not provide definitive recommendations for modifying Ontario’s transmission rate, they do highlight the importance of local issues in transmission design. More generally, the experiences of other jurisdictions also help us better understand how various criteria and concerns in rate design have been resolved such as the equal treatment of transmitters for instance. A number of interesting points arise from the case studies, which are relevant to the current situation in Ontario.

First and foremost, regardless of the transmission access charge design being employed, these have generally been implemented in a fair and transparent manner in the US, principally due to the uniform FERC mandated Open Access Transmission Tariff (OATT) guidelines the ISOs have to comply with. The FERC pro forma OATT, which serves as the basis for all OATTs in the US, details the nature of the two transmission services to be provided by transmission owners, notably point-to-point and network integration service. Transmission rates in US jurisdictions are developed based on the OATT, usually through RTO/ISO tariff committees within each ISO. The OATT applications once completed by the respective utilities are submitted to FERC for approval.

Furthermore, the pro forma OATT distinguishes between firm and non-firm services for point-to-point services. The FERC pro forma OATT also stipulates the way in which the access charges should be computed. These are simply derived by allocating a revenue requirement across billing units which, depending on the jurisdiction, are done ex-post by estimating actual

\[23\text{ Docket No. EL05-121-000, 002}\]
energy throughput in MWh (for example, as used by NYISO) or ex-ante based on coincident peak measures in MW terms using historical data (for example, PJM relies on coincident annual peak demand, while MISO uses the twelve coincident peaks). The data used in the development of the revenue requirement is based on the transmission provider’s FERC form 1 filings.

In jurisdictions which currently have license-plate rates for transmission access, these were initially put in place due their relative ease of implementation compared to a postage stamp system, given the presence of multiple transmission providers and the fact that each had a distinct rate based on its unique ratebase and customer pool. While in some jurisdictions this license-plate system is considered transitional, and uniform transmission access pricing is the final goal (for example, in CAISO), this is not universal. Some jurisdictions (PJM and MISO, for example) are still unsettled about future market design, because of the challenge of blending many different rates. The incentives to move to postage stamp rates in New York, PJM and MISO are also blunted by the fact that license-plate rates can co-exist with the policy objective of removing rate pancaking. More practically, markets with license-plate rates (such as PJM and NYISO) have not faced any substantial criticism with their current zonal approach, which regulators (like FERC) have equated with efficient market operations. Furthermore, although a postage stamp rate has been favored by regulators on the basis of economic traits of transmission (public good criteria and positive externalities), the use of postage stamp rates has also raised the issue of equity. For example, in New England, the presence of pooled rates and socialization of costs has been identified as one of the primary obstacles in getting new transmission approved. The debates are not focused on the computation of the access charges, as New England has a transparent process through which these are annually reviewed, as well as a yearly balancing account. Rather, the main debate revolves around the socialization of transmission upgrade costs of the “pool transmission facilities”\(^{24}\) described in detail further on, which some argue are unfairly allocated to those transmission ratepayers who do not necessarily benefit the most from the upgrades.

Interestingly, the concept of socialization is more commonly applied to transmission upgrades. As discussed further below, ISO-NE has a bifurcated approach, based on whether or not the upgrade is designated as a Pool facility. Pooled assets are then socialized across customers. This approach is similar to that in Alberta where transmission upgrades are paid for by all ratepayers. In PJM, all high-voltage upgrades (above 500 kV) will now be socialized across all ratepayers. Similarly, new high voltage upgrades in California are allocated to the grid-wide rate component and are therefore being socialized. Only in NYISO are transmission upgrades paid for by those customers within the respective transmission areas in which the network is being upgraded.

\(^{24}\) Indeed, in ISO-NE, the costs of upgrades to pool transmission facilities are recovered through the RNS rate which applies to all customers, and as such, these costs are socialized. The Qualified Upgrade Awards (QUAs) detailed later on in this Chapter only apply to those transmission facilities not covered by the RNS rate.
Lastly, in order to prevent over-charging of consumers in LMP-based markets (and even in zonal wholesale markets, like California), accounting linkages are set up between transmission congestion costs (which are part of the commodity price) and transmission access charges. Both types of charges effectively defray a “cost of service” transmission usage service. In order to allow transmission users to hedge congestion costs, market operators auction off transmission rights. The revenues generated by the sale of the transmission rights (which are known as FTRs, CRRs, or TCCs) or the auction receipts from the sale of the rights are then eventually used to reduce the costs of transmission access through the reduction of the revenue requirement from which the transmission access charges are derived. In NYISO, PJM, and California for instance, the revenue requirements used as a basis for deriving transmission access charges are reduced by the amount of revenues generated from the sale of such rights. In New England, the auction revenues from the sale of FTRs are credited directly to load.

2 FERC’s Open Access Transmission Tariff (OATT)

In the United States, regional transmission organizations (RTOs) are mandated by the Federal Energy Regulatory Commission (FERC) to provide for open-access to their transmission system to ensure a fully competitive market environment. In these RTOs, the connection rules and transmission pricing methodology are transparent and accessible to generators and load alike and are regulated by the RTOs through a FERC approved Open Access Transmission Tariff (OATT), which is essentially a cost of service tariff. All of the US case studies discussed in this Chapter have transmission access charges which are derived from the FERC mandated OATT and approved by
FERC, and as such it is essential to understand its intricacies.

In April 1999, FERC issued final rulings on Order 888 - “Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs By Public Utilities and Transmitting Utilities,” and Order 889 - “Open Access Same-Time Information Systems” or “OASIS” (see text box). The OATT mandated by these orders, was established by FERC to prevent public utilities engaged in wholesale power marketing functions from obtaining preferential access to pertinent transmission system information. The OATT determines prices for various categories of transmission service (predominantly for firm and non-firm point-to-point transmission service) and defines distribution of transmission revenues among the transmission owners (TOs). It also details interconnection rules and obligations for generators, merchant transmission owners and regulated TOs. Financial transmission rights (FTRs) are also defined by the OATT, as are the rules related to their accounting and settlement process.

To facilitate the implementation of these Orders, FERC created a proforma open-access tariff on which all of the OATTs of the jurisdictions covered in this Chapter are based. The proforma OATT details the nature of the two transmission services to be provided notably point-to-point and network integration service. For point-to-point services, the FERC pro forma OATT distinguishes firm from non-firm service specifying the various provisions specific to both service types. The provisions in the pro forma OATT detail the characteristics of each type of transmission service with regards to their term (length of reservations), reservation priority (detailing an order of curtailment) and scheduling for instance. The FERC OATT pro forma also details the provisions under which discounts may be offered to transmission customers for both firm and non-firm transmission service. Indeed the pro forma states that when rate discounts are offered, they must be offered at the same time to all eligible customers for the same transmission path. Furthermore,
information regarding any firm or non-firm transmission service discounts must be posted on the OASIS website of the ISOs.

Rates for transmission service as per the FERC OATT are derived by determining the transmission owner’s revenue requirement and then dividing it by a measure of network load. It is worthwhile to note that although the FERC pro forma provides for a general calculation framework, it does leave each individual ISO with the flexibility to set rates it deems appropriate. The transmission owner’s revenue requirements are derived based on the information they provide in FERC Form 1 (electric utilities annual report) and are calculated as:

\[ \text{Revenue requirement} = \text{Expenses} + (\text{Ratebase} \times \text{Allowed return}) \]

The formula is basically a two stage calculation whereby the ratebase is first determined followed by the revenue requirement. The ratebase generally includes the book value of assets, any depreciation and allowance for working capital. The ratebase is then used as the basis upon which the allowed rate of return is applied. To this amount are then added all the appropriate operating expenses such as labor, depreciation and corporate taxes for instance.

For network service specifically, the pro forma stipulates that customers are required to pay the transmission provider for any direct assignment facilities, ancillary services, and applicable study costs in addition to a monthly demand charge. This charge is calculated by multiplying the customer’s load ratio share times one twelfth of the transmission provider’s annual revenue requirement. The load ratio share is calculated on a rolling twelve month basis. The OATT defines a network customer's monthly network load as the hourly load coincident with its monthly transmission system peak.

Under the open-access regime, independent system operators are required to develop a process to provide system users with information on available transmission capacity, as well as a process to reserve such capacity. Available Transmission Capacity (ATC) is calculated for the entire network by each ISO as per FERC and NERC criteria and are posted on each of the ISO’s OASIS website. The Total Transfer Capability (TTC) for a network is the best engineering estimate of the total amount of electric power that can be transferred over the network in a reliable manner in a given time frame. Typically the ISOs forecast the TTC for each interface of their network based on thermal, voltage, and/or stability limitations of the ties that comprise the interface. ISOs generally post hourly, daily, weekly and monthly TTC estimates. The ATC is simply an adjusted measure of the network’s TTC which factors in the usage or forecasted usage of the system. Indeed the ATC measures not only incorporate the transmission schedules submitted by the respective transmission users, they are also automatically updated as soon as any usage request is received by the ISO using a power flow simulation. Non-firm service is typically scheduled based on the residual capacity of the system once all firm or native load obligations have been scheduled.
Furthermore ISOs are also required to establish clear principles to allocate capacity among competing users through a fair and transparent mechanism. Such transmission capacity is allocated on a first come first served basis with preference given to capacity reservations of greater size and length. Indeed a reservation for a 60 MW for a year would generally take precedence over a reservation of 50 MW for a year as it would over a reservation of 60 MW for six-months. In the event of a lack system capacity however, firm reservations, by nature, take precedence over non-firm ones. It is important to note that no capacity allocations are based on prices as all transmission usage is priced transparently on a cost of service basis, regardless of the reservation. To ensure such transparency, RTOs provide data, by electronic means, on available transmission capacity, prices, and other information. Depending on the structure of the regional market, the OASIS sites can cover small sub-regions or larger service territories. In PJM, for instance, the RTO operates a single OASIS site for all transmission facilities under its control.
3 Alberta ISO (AESO)

3.1 Introduction

The transmission service charge (known as the Interconnection Charge) in the province is based on a postage-stamp rate design which means that a uniform price for transmission services is applied across the entire market and that each customer has the same rate irrespective of their geographical location. The costs associated with the expansion of the transmission system are borne by customers.

Although Alberta is not under FERC jurisdiction, it is part of North American Electric Reliability Corporation (NERC) and therefore follows the same key network operating protocols as its US counterparts. In addition, in order to gain reciprocal status for cross-border trading, Alberta TOs have a tariff consistent with FERC’s pro forma OATT.

The Alberta Electric System Operator (AESO) oversees the workings of Alberta Electric Interconnected System (AEIS), an independent entity responsible for running a reliable and efficient transmission system. The transmission system consists of the Bulk System defined as the system that delivers bulk electric energy (large volume) over a long distance (i.e. interprovincial interconnections) and the Local System providing services to local points of delivery.

The Alberta Electric System Operator (AESO) was created in 2003 from two already existing entities, the Power Pool of Alberta and the Transmission Administrator of Alberta.

The AESO covers over 21,178 km of transmission lines and has 4 transmission service providers: AltaLink, ATCO Electric, ENMAX and EPOCOR.

Major transmission owners are AltaLink with approximately 11,600 km of transmission lines, serving 85% of Alberta’s population and ATCO Electric, with approximately 8,900 km of transmission lines.

Alberta has a peak load of 9,236 MW and 12,006 MW of installed capacity.

In Alberta, all transmission facilities are planned by the AESO and, with the exception of merchant transmission facilities25, built and operated by a regulated TO on a cost of service basis. The widely dispersed load and concentrated generation in the energy market are some of the reasons behind the postage-stamp rate design in the province.

Initially, congestion was not a concern in Alberta. The use of a single pool price concept in its wholesale market design26 means that costs associated with congestion are socialized across all

25 Alberta currently has a proposal for two merchant transmission facilities.

26 Alberta’s energy wholesale market operates on a least-cost dispatch basis where the cheapest available units on a marginal cost basis are dispatched first.
customers. However, over the last few years, congestion issues have become a growing problem. As of now, there is no system in place that deals with the pricing of congestion, although one has been recently proposed (please see Section 3.3 of this Chapter for more detail.)

The AESO’s current response to the rising congestion problems is the expansion of the transmission system. Customers pay for all costs associated with the network expansion on the premises that all customers equally benefit from the more efficient transmission network. The AESO continues to plan and approve new projects. The costs of transmission system losses are allocated to generators through a transmission usage charge (known as Losses Charge) they are assessed when contracting for Supply Transmission Service, in accordance with section 22 of the Transmission Regulation. The Supply Transmission Service and the Losses Charge are described in more detail in the following section of this Chapter.

Figure 5. Alberta’s bulk transmission system

Source: Energy Velocity

3.2 Access to Transmission Services and related charges

The AESO’s transmission tariff is approved by the Alberta Energy and Utilities Board (AEUB) pursuant to sections 30 and 119 of the Alberta Electric Utilities Act S.A. 2003 c.E-5.1. As mentioned before, the tariff is based on a postage stamp rate design even though Alberta has multiple transmission service providers. As such, transmission service customers in Alberta pay a uniform price for transmission services regardless of the identity of the transmission provider or location.

The AESO determines its transmission tariff based on the estimates of TOs’ revenue requirements and the AESO’s own costs. The annual rates, which are designed to cover the revenue requirements and guarantee equal treatment based on AESO load forecasts, are approved by the regulator, the AEUB (Alberta Energy and Utilities Board). If the actual collected revenues differ from the estimated revenues, again based on AESO’s load forecasts, the difference is controlled by the AESO, using a deferral account. Over the course of the year, the difference is covered by the AESO, but ultimately it is collected or paid back using the deferral account in the subsequent year’s revenue requirement assessments.

To access Alberta’s transmission system, customers must apply for interconnection and obtain a system service access agreement with the required transmission facilities. In addition to the customer and the AESO, the AEUB plays a key role in the interconnection process. In general the transmission tariff is decided in two stages:

- In Phase I – The AESO sends an application to the AEUB determining its revenue requirement. The AESO’s application includes the approved transmission rates of the TOs (approved through a separate process) in addition to the AESO’s own operation costs.

- In Phase II – The AEUB rules on the AESO proposed allocation of costs between the different classes of customers and determines the rates sufficient for the AESO to recover the revenue requirement determined in Phase I.

There are two types of transmission services administered by the AESO: Demand Transmission Services (DTS) and Supply Transmission Services (STS). DTS is for demand customers (load) whereas STS is for generators. In other words, in Alberta, both load and generation pay for transmission access (in contrast, across the US, typically only load, as transmission users are required to pay the access charge).

DTS is available to demand customers who, in order to obtain transmission service, have to apply for a Capacity Contract.28 The contract details each user’s peak demand and is effectively

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28Capacity contracts (part of Alberta’s System Access Service Agreement) are used by transmission customers to specify the capacity (in MW) they need (i.e. peak demand for load customer or supply capability for supply customers).
a reservation for firm transmission service. The DTS price is calculated as the sum of the following charges:

- Interconnection Charge (composed of bulk system charge, local system charge and point of delivery charge),
- the Operating Reserve Charge,
- the Voltage Control Charge, and
- the Other System Support Services Charge.

Figure 6, below, which highlights the four DTS rate components together with their associated rate levels serves to illustrate the fact that the transmission access charge (interconnection charge) represents the larger portion of the rates incurred by demand transmission customers.

<table>
<thead>
<tr>
<th>DTS Rate</th>
<th>Rate Level</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Interconnection Charge</strong></td>
<td></td>
</tr>
<tr>
<td>(1) Bulk System charge</td>
<td></td>
</tr>
<tr>
<td>(1)(a) Coincident Metered Demand</td>
<td>$1,233.00 /MW</td>
</tr>
<tr>
<td>(1)(b) Metered Energy</td>
<td>$1.41 /MWh</td>
</tr>
<tr>
<td>(2) Local System Charge</td>
<td></td>
</tr>
<tr>
<td>(2)(a) Billing Capacity</td>
<td>$553.00 /MW</td>
</tr>
<tr>
<td>(2)(b) Metered Energy</td>
<td>$0.26 /MWh</td>
</tr>
<tr>
<td>(3) Point of Delivery Charge</td>
<td></td>
</tr>
<tr>
<td>(3)(a) Billing Capacity</td>
<td>$707.00 /MW</td>
</tr>
<tr>
<td>(3)(b) Metered Energy</td>
<td>$0.08 /MWh</td>
</tr>
<tr>
<td>(3)(c)(i) Multiple End-Users Charge</td>
<td>$21,899.00 /month</td>
</tr>
<tr>
<td>(3)(c)(ii) Single End-User Charge</td>
<td>≤ 5 MW $4,380.00 /MW</td>
</tr>
<tr>
<td></td>
<td>&gt; 5 MW $21,899.00 /month</td>
</tr>
<tr>
<td><strong>Operating Reserve Charge</strong></td>
<td></td>
</tr>
<tr>
<td>(4) Metered Energy × Pool Price</td>
<td>3.87% × Pool Price</td>
</tr>
<tr>
<td><strong>Voltage Control Charge</strong></td>
<td></td>
</tr>
<tr>
<td>(5) Metered Energy</td>
<td>$0.98 /MWh</td>
</tr>
<tr>
<td><strong>Other System Support Services Charge</strong></td>
<td></td>
</tr>
<tr>
<td>(6) Highest Metered Demand</td>
<td>$76.00 /MW</td>
</tr>
</tbody>
</table>

Source: AESO Bill Estimator available on the website at [www.aeso.ca](http://www.aeso.ca). The rates shown are in effect since January 2007.

In addition to the firm transmission service demand customers can obtain through DTS, customers can also obtain interruptible transmission service known as Demand Opportunity Service (DOS) in the event their load increases above the levels they had initially contracted for.
It should be noted however that DTS customers have to pre-qualify in order to be eligible for DOS\(^{29}\) and that DOS is only available if there is a surplus of capacity in the market.

The ability to obtain interruptible DOS service allows those demand transmission customers to reduce their costs of acquiring transmission capacity beyond their contracted DTS levels. Indeed, since DOS only provides incremental capacity, DTS users who use DOS, avoid setting a new Billing Capacity\(^{30}\) (a costly settlement option) and instead obtain additional transmission service, albeit interruptible, at the relatively reduced cost of DOS. As an example, a DTS customer with a contract capacity of 60 MW, who wishes to serve 65 MW of load in a given month would have to increase its DTS contract capacity to 65 MW if DOS service was not available.

The AESO charges a price for DOS that includes a set monthly transaction fee of Cdn. $500 plus the minimum charge per DOS transaction based on the customer’s requested DOS capacity. It should be noted that the DOS capacity referred to as the Billing capacity replaces the DTS contract capacity when demand customers use DOS.

There are three DOS services: DOS 7 Minutes, DOS 1 Hour and DOS Term (the term is actually 7 minutes but in the event of curtailment, it is scheduled after the DOS 7 Minutes and DOS 1 Hour.) DOS customers pay a fixed monthly transaction fee of Cdn. $500 in order to use the DOS services plus the costs of DOS transactions. These transaction costs are assessed by multiplying the capacity contracted under DOS by the term (hours) of DOS transactions and then further multiplied by 75% and a fee that varies depending on the type of DOS service used ($3/MWh for DOS 7 Minutes, $5/MWh for DOS 1 Hour and $20/MWh for DOS Term.) The AESO uses the revenues from the sale of DOS to offset the transmission access charge to all market participants. In essence, revenues derived from interruptible service (DOS) serve to reduce the revenue requirements used to calculate DTS service charges.

As mentioned earlier, in addition to the transmission usage charges for demand customers, Alberta also has such charges for supply customers which are referred to as Supply Transmission Service (STS) charges. STS customers (generators) supply energy into the Alberta market. These customers pay what is known as Losses Charge, in order to be able to supply

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\(^{29}\) In order to qualify for DOS customers have to apply and be approved for a status of a DOS user at least 30 days in advance of using the DOS service. It is a multi-stage process between the customer and a transmission owner or between the customer and AESO directly. The details of the application process are available on the AESO website <http://www.aeso.ca/files/2007_DOS_Business_Practices_Final.doc>.

\(^{30}\) Billing Capacity refers to a measure of customers’ use of interconnection capacity. The value can be expressed in peak capacity, reserved capacity or previously filed billing capacity pending which amount is greater.
electricity. The losses charge is equal to metered energy\textsuperscript{31} multiplied by locational loss factor (specific to each generator)\textsuperscript{32} and by the AESO wholesale market price.

\begin{table}[h]
\centering
\begin{tabular}{|c|c|}
\hline
Rate Component & Rate Level \\
\hline
Losses & \begin{tabular}{c}
Metered Energy \times \text{Loss Factor} \times \text{Pool Price} \\
5.41\% \times \text{Pool Price}
\end{tabular} \\
\hline
\end{tabular}
\caption{STS rate and applicable charge in AESO}
\end{table}

\textit{Source: AESO Bill Estimator available on the website at www.aeso.ca. The rates shown are in effect since January 2007.}

3.3 Linkages between transmission access charges and Alberta’s wholesale market

The AESO operates a single real-time wholesale market. Participants, which include power generators, consumers and marketers, are not required to participate in the market as it is a “loose pool” and participation is therefore not mandatory. Prices are set through the Energy Trading System (ETS) in which bids and offers are combined in order to determine the system marginal price (SMP). Bid prices are capped at Can $ 999/MWh. The SMP is determined by the price of the last energy block dispatched in that minute. The hourly price is obtained by calculating, at the end of each 60-minute period, the time-weighted average of each 1-minute intervals’ SMP during that period.

Alberta does not currently have a locational marginal price (LMP) market design. As a result, Alberta does not support FTRs which require an LMP market design to be implemented effectively. The costs associated with congestion are therefore embodied in the transmission access charge paid by all customers. As noted by the Alberta EUB in its Decision 2002-099:

\begin{quote}
\textit{The Board is of the view that financial transmission rights (FTRs) would not be meaningful, unless an LMP system were to be implemented in Alberta. In order for FTRs to work and fulfill their intended purpose, there must be price differentials at different points (or nodes) on the system. Creating this environment would require substantial market re-design in Alberta.}\textsuperscript{33}
\end{quote}

However, with costs related to congestion on the rise, in April 2005, the AESO formed the Transmission Constraints Management Working Group which later that year produced a report entitled “Constraints Management Discussion Paper” for stakeholder comment; effectively initiating the process of considering congestion management in Alberta. The premise of this proposal was for the AESO to use a priority based curtailments mechanism to manage congestion. However, the feedback received from stakeholders regarding this proposal was negative and was specifically critical of the part of the proposed methodology which called for

\textsuperscript{31} Measured in 15-minute intervals.
\textsuperscript{32} These loss factors are customer specific and determined by the AESO using a complex matrix which seeks to isolate the impact of each generator on network losses using a algorithm based transmission flow simulation exercise.
\textsuperscript{33} AEUB Decision 2002-099 (Pg. 127-128).
the AESO to identify market participant as a “trigger” in the event of transmission constraint. This “trigger” participant status meant that in the priority based curtailment system, that participants would be curtailed before STS customers (generators) and after the opportunity services (DOS) customers. As a result of this negative feedback, the Working Group is planning to propose a new constraints management methodology by the fourth quarter of 2007. While it is clear that AESO will be using curtailments to manage congestion in the market, the way in which these curtailments are going to be prioritized will undoubtedly remain an issue among stakeholders.
4 California ISO (CAISO)

4.1 Introduction

The California Independent System Operator (CAISO) is the control area operator for the majority of the high voltage transmission within California (it does not cover the entire state). The wholesale market design under the jurisdiction of CAISO is based on a zonal network model consisting of three areas. These areas are: North area (NP15), the South area (SP15) and the East/Central (ZP26) area. The overall market has nearly 30 inter-zonal interfaces and congestion is priced at all of these inter-zonal interfaces.

The Transmission Access Charge (TAC) is in place for each of the three existing areas. The TAC is a blended rate comprised of two components: the TAC area component and the CAISO grid-wide component. In September 2006, FERC conditionally approved a new nodal wholesale market design known as the Market Redesign Technology Update (MRTU). MRTU is scheduled to be implemented in February 2008, but the new market design will not materially affect the way in which the transmission access charge is assessed.

Under the TAC methodology, transmission owners continue to be charged a utility specific rate\(^{34}\) until they decide to integrate into the TAC area rate design. The TAC area rate design is a transitory design put in place to allow market participants to plan for the market with a postage-stamp based transmission access charge and avoid rate shocks associated with a change of the market rate design. For the original CAISO members, the transition period runs from the beginning of January 2001 through December 2011. CAISO actively manages cost shifts occurring due to the market’s transitioning to the new transmission rate design. Indeed CAISO has, for instance, limited cost-shifts to the native transmission owners when new transmission owners join the transmission network. This limit has been set at $72 million spread among all native TOs and distributed among the existing three TAC areas NP16, SP15 and ZP26 according

\[^{34}\text{ Prior to creation of TAC areas, CAISO had control areas upon which this (zonal) pricing system was based.}\]

CAISO began operations in 1997. It is a FERC approved RTO as per FERC Order in 2000 and as such it has under its footprint most of the California energy market. It oversees about 41,000 km of transmission network system. CAISO administers Transmission Access Charge (TAC) as per FERC Order 888.

The peak demand in CAISO is recorded at 45,431 MW. The market has installed capacity of 54,500 MW and serves about 30 million people.

Each of the three control areas in the market has at least one transmitter. Currently the NP15 zone has only Pacific Gas & Electric; the SP15 zone has San Diego Gas & Electric Company while the ZP26 zone has Southern California Edison and the Cities of Azusa, Anaheim and Banning Riverside.
to a 32/32/8 ratio. However the cost-shifts associated with newly built high voltage facilities are not limited to this pro rata sharing method.

New TOs, upon joining, are typically incorporated into appropriate existing areas, although, in some cases, new areas may be formed. For example, CAISO has stated that it will create a forth TAC area (the West Central Area) if the Los Angeles Department of Water and Power joins the CAISO controlled market.

Under the current market design, the local or intrazonal congestion costs (for example within the NP15 zone) are borne by all customers in that area since CAISO does not explicitly provide a more specific locational price, but simply charges additional redispatch costs to alleviate congestion. All customers uniformly pay the costs of local congestion within their area.

**Figure 8. TAC areas and transmission paths in CAISO**

![CAISO TAC areas and transmission paths](source: CAISO)

### 4.2 Transmission services related charges

CAISO provides the following transmission services: network integration transmission service and point-to-point transmission service (long-term and short-term firm and non-firm). CAISO has two main types of access charges for the above services: the High Voltage Access Charge-HVAC (above 200 kV), which includes a transition charge discussed further below and the Low Voltage Access Charge-LVAC (200 kV and below). Both, HVAC and LVAC are derived from the TOs filings of annual revenue requirements. The revenue requirement of the TOs in CAISO is the sum of the HVAC and LVAC revenue requirements. For each TO, the HVAC annual rate for transmission services ($/MW) equals the ratio of the TO’s FERC approved net HVAC revenue requirement to the network peak demand averaged over the previous 11 months (12 CP). The LVAC rate is determined and administered by TOs themselves however, the revenue
from this charge is reported in the TOs revenue requirement filing and subject to FERC approval. Therefore the level of LVAC assessed in the market corresponds to the revenue needed to recover the TO’s LVAC revenue requirement component.

The HVAC rate consists of two main components, a TAC area component charge (which is zonal) and a system-wide charge.

The transmission revenue requirement for the TAC area component is calculated with the following formula:

$$\text{Sum of all TOs’ revenue requirements in a TAC area } \times \text{ applicable annual Transition Charge (\%) } / \text{ the Gross Load in the TAC area}$$

The transmission revenue requirement for the CAISO grid-wide component is calculated by the following formula:

$$\frac{(\text{Sum of all existing TOs’ revenue requirements in a TAC area } \times \text{ applicable annual Transition Grid Charge (\%) } + \text{ Sum of all new TOs’ revenue requirements in a TAC area })}{\text{the Gross Load in the TAC area}}$$

Knowing the two components of the TAC rate enables the transmission owner to calculate its Transition Charge, a rate it needs to pay in order to join the TAC area system. The transition charge is essentially a factor which allows for the gradual transmission in HVAC rates over time which are intended to reflect a greater proportion of the system-wide component relative to the TAC area component. Indeed, HVAC will in 2011 become a uniform grid-wide charge for all market participants. During the TAC rate design tenure, the HVAC will transition 10% per year to the CAISO grid-wide rate. In the first year (2001) the HVAC was a blend of 10% of the grid-wide rate and 90% of the TAC area component.

New TOs can join the CAISO market at the beginning or midway through year. These new TOs’ Transition charge depends on the year they join. For example if they join in 2007, their Transition Charge (for the existing facilities) is split 70% for grid-wide component (the transitioning rate of 10% multiplied by the years in transition) and 30% for the TAC area component. The revenue requirement of new HVAC facilities is not included in the calculation of the Transition Charge and thus their HVAC is 100% grid-wide rate, which is similar to the treatment of such facilities mandated by FERC for PJM, as is further discussed in Section 8.

The HVAC rates are adjusted annually when the TO has a newly approved FERC revenue requirement. The TAC area rate component of the HVAC is subject to changes in the TOs’ revenue requirement while the grid-wide rate component of the HVAC is affected by changes
in the TOs’ Transmission Revenue Balancing Account (TRBA). The TRBA is an element of the transmission revenue requirement established and approved by FERC to ensure that revenues received by a TO for wheeling service, usage charges, and sales of FTRs flow through to final transmission customers. Consequently, through this TRBA, all revenues from wheeling, usage charges and the sale of FTRs decrease the revenue requirement on which the HVAC is derived and thus serve to reduce access charges for high voltage customers.

Finally, with regards to new high-voltage transmission upgrades, their costs are included into the grid wide component of the HVAC payable directly to CAISO. CAISO then distributes the access charge revenue. The allocation of access charge revenues to a TO depends on whether the TO in question is a native TO or a new TO with or without load. While the TAC revenue payments to TOs are calculated daily, CAISO collects and distributes the TAC revenues monthly. The TAC revenue is composed of the revenue from the TOs with daily metered quantities (meaning they have utility distribution business and serve native load) and the revenue from the TOs with no load. The TOs with no load receive their portion of the TAC revenue based on the ratio of their HVAC transmission revenue requirement to the sum of all the TOs HVAC transmission revenue requirements.35 The TOs which are also serve native load through their affiliate utility distribution businesses receive the revenues from the metered demand portion of the TAC revenue assessed at the utility’s specific HVAC rate.

Once CAISO completes the distribution of the entire TAC revenue among all participating TOs (with and without load), if the balance is not zero, CAISO then calculates a so called HVAC revenue adjustment, which whether positive or negative is allocated to those TOs with load based on the ratio of each TO’s HVAC revenue requirement to the total transmission requirement of all TOs with load.

Those TOs, which prior to joining the CAISO TAC area had existing contracts with customers (which means that a utility specific rate is applied), would have to credit the revenues from these contracts against the HVAC portion (in the case of a high voltage facility) of their revenue requirement. Therefore, those TOs that are paying charges associated with an existing contract are permitted to include these charges in their annual revenue requirement submissions. For low voltage facility, revenues from the existing contracts are credited to the HVAC and the LVAC portions of revenue requirement based on the HVAC to LVAC revenue requirement ratio of each TO.

The other transmission access charge administered by CAISO, notably the Low Voltage Access Charge (LVAC), is governed by the same rules the HVAC with the notable distinction that it is a utility-specific rate. It is determined and collected by each TO. If a TO is using the low voltage transmission facilities of another TO, it too will be assessed the LVAC of the TO whose facilities

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35 The revenue requirement of each TO is the sum of the HVAC revenue requirement and the LVAC revenue requirement.
it is using. Additionally, the Wheeling Access charges in CAISO are equal to the HVAC for the applicable TAC area plus the applicable LVAC charge if the scheduling point is on a low voltage transmission facility. As such, there is no distinction between the transmission access charges (HVAC and LVAC) and the wheeling charge in CAISO.

### Figure 9. Current transmission access rates in CAISO

<table>
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<tr>
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<th>Scheduling Points</th>
<th>Voltage Level (kV)</th>
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<th>LV Rate ($/MWh)</th>
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### 4.3 Linkages between transmission access charges and commodity prices in CAISO

California’s existing market design deals with the issues of congestion in real time, so occasionally buyers and sellers submit schedules that cannot always be accommodated on the transmission system. In order to hedge this risk for market participants, CAISO holds annual auctions of FTRs on the interzonal paths, as shown in Figure 8. In the current CAISO market, the FTRs are not just financial instruments used for hedging, but also serve as physical rights to
scheduling priority in the forward market.\textsuperscript{36} The amount to be auctioned on these inter-zonal interfaces is determined by first taking the 8760 hours of the most current Available Transfer Capability (ATC) data ranking it first from highest value to its lowest value. Then the amount of capacity that is to be auctioned is calculated as the amount corresponding to a 99.5\% availability level.\textsuperscript{37}

The auction revenue is then distributed to participating TOs. Each TO is then required to credit its FTR auction proceeds against its TRBA\textsuperscript{38}. Indeed, the TRBA account is adjusted annually to reflect any transmission revenue credits which include revenue from wheeling services, usage charges, and sales of FTRs. The TRBA is then added on to the transmission revenue requirement of each TO to determine their total HVAC transmission revenue requirement. As a result, the proceeds from the FTRs auction, in addition to any revenues for wheeling service can lower or increase the following year’s HVAC charge.

In the event the transmission facilities or rights are owned by more than one TO, the FTR revenue is distributed to those TOs (who auction FTRs) proportionally based on their number of FTRs compared to all FTRs auctioned within a specific inter-zonal interface. If the transmission facilities or rights making up an inter-zonal interface have been upgraded to increase their transmission capacity and the costs of construction and operation were not included into the HVAC, or paid for by a participating TO, such project developer and financier is paid with the FTR revenue in proportion to its allocated share of FTRs as pre-defined by CAISO.\textsuperscript{39}

\textsuperscript{36} The FTR holder is entitled to receive from CAISO a portion of the total congestion revenues calculated in the Day-Ahead market with respect to the inter-zonal interface and direction combination for which the FTR was defined. CAISO will allocate revenue to the FTR holder by first calculating the usage charge from the Day-Ahead market for the transfer of 1 MW from the originating TAC area to the receiving TAC area during each hour in which usage charges apply, and multiplying it by the number of FTRs owned by that FTR holder. The FTR holder is also entitled to a portion of additional revenue for the net usage charges related to inter-zonal congestion calculated in the Hour-Ahead market and collected by CAISO. This amount will be proportionate to the share of the usage charges revenue received in the Day-Ahead market.

\textsuperscript{37} Operating Transfer Capability on Inter-zonal Interfaces accounted for (subtracted from) Existing Transmission Contracts (ETCs) equals Available Transfer Capability in this context.

\textsuperscript{38} If a TO does not have a TRBA, the FTR proceedings are credited against its revenue requirement approved in the most recent FERC filing. Also, TRBA distinguishes between credits associated with the LVAC and HVAC and related FTRs, thus FTR revenue associated with the high voltage FTRs is credited against the TRBA high voltage portion of revenue.

\textsuperscript{39} From the CAISO TAC: “The Project Sponsor’s share of Wheeling, Congestion and FTR auction revenues for the upgraded transmission facility shall be the number that is determined by dividing the number that is determined by subtracting the rating of the transmission facility before the upgrade from the new rating for the upgraded transmission facility by the new rating for the upgraded transmission facility. The Participating TO’s share of Wheeling, Congestion and FTR auction revenues for the upgraded transmission facility shall be the number that is determined by subtracting the Project Sponsor’s share from one hundred percent (100\%). Such allocated shares shall become effective on the date the new rating takes effect.” (Section 3.2.7.3. (d))
In Order 681 FERC adopted a final rule requiring organized electricity markets to offer LSEs long-term FTRs covering existing transmission capacity for a minimum of 10 years. Until now, FTRs have generally been available only for terms up to one year (the exception being New York, which has tried auctioning of five year TCCs). The introduction of long-term FTRs would allow transmission customers in LMP markets to commit to long-term power supply arrangements.

In its Order No. 681 FERC stated that significant changes to the rate design of the markets which at the moment utilize FTRs are not expected. In fact FERC thought that the current market design addressing the allocation and auction of FTRs can remain the same in most markets and adjusted to the use of long-term FTRs. PJM, MISO and CAISO have all begun to integrate long-term FTRs into their markets, although many details remain to be decided. FERC recently approved both PJM and MISO’s long-term FTR proposal.

Unlike FTRs described above, CRRs will only serve as financial instruments (similar to the design in other LMP markets). CRRs will be allocated to LSEs serving load in the market as they are in New England and the allocation system is going to be priority based with a proposal for some LSEs to receive CRRs free of charge on the premises that they have been paying for congestion costs embedded in the transmission system.

The initial allocation proposal called for two-tiered CRRs: long-term CRRs (available for one year) and short-term CRRs (available for one month). To types of CRRs will be offered; Obligation and Option CRRs (which refers to the uni-directional or bi-directional nature of the CRR). For example FTR Obligations can be negative and represent a liability (the designated path is in opposite direction of the congestion flow) or can be positive (the FTR designated path is in the same direction as the congestion flow) and represent a benefit to the holder. FTR Options are positive meaning that designated path (from power sink to the power source) is in direction of the congestion flow resulting in the positive difference between locational prices registered at the

In contrast to the zonal congestion pricing system in place currently, the conditionally approved new market design will use a nodal (LMP) system and enable the CAISO to identify more granular constraints on the grid as early as the day ahead, price local congestion, and adjust scheduling accordingly. Under the new market system, CAISO will allow market participants to hedge against congestion using congestion revenue rights (CRRs) which are to be initially available through an allocation process as well as a system of auctions.
sink and at the source. The revenue from the CRR auctions will flow directly into the TO’s TRBA the way currently the revenue of FTR auctions does. 40

In accordance with FERC Order 681 requiring RTOs to establish long-term firm transmission rights, CAISO will introduce 10 year CRRs. These CRRs will be seasonal and differentiated by the time-of-use periods (on-peak and off-peak) for each day within a season. These very long-term CRRs will be allocated to LSEs in accordance with (yet to be fully defined) annual CRR Allocation process and will not be available for the CRR Auction.

40 Since this new market design had been approved, the CAISO began preparations for the CRR Allocation and CRR Auction processes which will take place later this summer (July and October respectively). As required by the May 8, 2007 FERC Order (Docket No. ER07-613-000), the CAISO will file the Business Practice Manual (BPM) for Candidate CRR Holder and CRR Registration Rules for FERC comment in early June 2007, so that the final rules are available in time for first annual CRR Allocation and Auction scheduled for July 9, 2007.
5 Midwest ISO (MISO)

5.1 Introduction

Transmission access charges in the Midwest ISO (MISO) are part of the Open Access Transmission and Energy Markets Tariff (TEMT). These access charges are based on a license-plate design put in place to accommodate the various transmission providers that joined MISO in April 2005. The TEMT contains two categories of rates: (1) zonal rates and (2) MISO system-wide rates. Zonal rates are applied to drive-in and drive-within transmission transactions (network service) while a MISO system-wide rate is applied to all transmission transactions that are drive-out and drive-through.

In 2004, FERC ruled in favor of the elimination of through and out charges at the border between MISO and PJM which it believed led to rate pancaking and disincentivized efficiency-enhanced trading between these two control areas. As a result of this ruling, MISO added another rate to compensate TOs for any lost revenue associated with the elimination of through and out charges at the PJM border. The new rate effectively works as an adder to the existing MISO through and out charge (equivalent of a 35% adder). Presently MISO’s seams issues with PJM are being worked out through a detailed Memorandum of Understanding (MOU). As outlined in more detail later in this Chapter, the short term alternative to through and out charges at the border between the PJM and the MISO, referred to as SECA charges, expired in April of 2006. The expectation is that eventually MISO will fully harmonize their transmission access charging policies with PJM’s. The future of MISO’s and PJM’s modified license-plate rate design will undoubtedly be the subject of numerous stakeholder debates in the coming months.

As a result of FERC’s firm stance on the elimination of rate pancaking, TOs in MISO are mandated to ensure that no pancaking charges occur even if some of them later leave MISO.

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41 In the recent FERC decision (April 19, 2007) on PJM market rate design (allowing continuation of the modified license-plate design), FERC reiterated that transmission owners operating within RTOs do so voluntarily, their participation subject to individual cost-benefit analysis. Should some transmission owners, due to the lack of through and out charges experience negative financial consequences they can bring their case before FERC.
fact utilities that eventually decide to leave MISO will be obligated to amend their tariff to state explicitly that the transmission access charges will not change for their existing customers.42

5.2 Access to Transmission Services and related charges

MISO, which implemented TEMT in 2005 as mandated by FERC Order 888, provides network integration transmission service and point-to-point transmission service (long-term and short-term firm and non-firm). The TEMT rate varies either by zone for all drive-in and drive within transmission transactions or is assessed as a MISO system-wide rate for all drive-through and out transmission transactions. The revenues derived from these rates are distributed to the TOs in proportion to their overall revenue requirement.

![Figure 10. Prices paid by transmission customers for network and point-to-point services*](image)

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<th>ZONE</th>
<th>Year 2007 MISO Rates for OATT Schedule 7, 8 and 9*</th>
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<td>American Trans. Sys 138KV and Above</td>
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<td>Indianapolis Power &amp; Light</td>
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<tr>
<td>24</td>
<td>Manitoba Hydro (representative rates $US)</td>
</tr>
</tbody>
</table>

The TEMT rate is derived from the TOs annual revenue requirement filings. For each TO, the zonal annual rate for transmission services ($/MW) equals the ratio of the TO's FERC approved net revenue requirement to the network coincident peak demand averaged over the previous 11

months (12 CP). The derived annual transmission access charge is then divided by the number of months, days, weeks and hours to obtain monthly, weekly, daily and hourly zonal charges. The MISO drive-out and drive-through average annual rate is defined as the ratio of all participating TOs’ net revenue requirements to network load (using the 12 coincident peak method). The revenue from all transmission services (network, firm and non-firm point-to-point services) is distributed to the TOs in proportion to their revenue requirement.

Figure 10 details rates for transmission services; a zonal price for deliveries within MISO applies for internal transactions, whereas wholesale transactions using the transmission system rely on the region-wide MISO through and out rate (first line item in the table). It should be noted that with regards to the table in Figure 10, the annual and monthly prices ($/MW per year and $/MW per month) are applicable to network and firm point-to-point customers only; and that non-firm point-to-point customers also have prices with hourly denominations not depicted in the table above.43

The MISO system-wide rate for through and out service listed in the figure does not include the additional charges under Schedule 14 of MISO’s OATT which are shown in Figure 11 (through and out compensation charge). These charges are only applicable to those TOs which, due to the elimination of pancaking rates with PJM, are faced with a revenue shortfall. This rate adder therefore only applies to through and out service to jurisdictions other than PJM. As a result, TOs that sink (deliver) in one of the PJM zones are paid that zone’s rate while the OASIS on the MISO side shows $0 amount for the same transaction.

<table>
<thead>
<tr>
<th>Figure 11. MISO prices for through and out services</th>
<th>On-Peak Rates</th>
<th>Off-Peak Rates</th>
</tr>
</thead>
<tbody>
<tr>
<td>$9,360.00</td>
<td>$780.00</td>
<td>$180.00</td>
</tr>
</tbody>
</table>

5.3 Linkages between transmission access charges and LMP design in MISO

In MISO, market participants use FTRs (Obligation and Option FTRs) to hedge congestion charges associated with their market purchases.

FTRs are currently both allocated and auctioned in the MISO market. The allocated FTRs, FTR “Entitlements” as they are called, are available primarily for the firm point-to-point transmission service and network integration transmission. Every year FTR Entitlements are allocated gradually through categories referred to as Tiers 1, 2, 3 and 4. Market participants have to qualify for FTRs under the rules of each Tier (as specified by the MISO in the Tariff) and the total number of FTRs obtained will be spread across Tiers in the following fashion: Tier I

43 All the prices can be found in a spreadsheet on MISO website at [http://oasis.midwestiso.org/documents/miso/pricing_new.html](http://oasis.midwestiso.org/documents/miso/pricing_new.html).
35% of FTRs for which the market participant was eligible, Tier II 50%, Tier III 75% and Tier IV 100%. The Tiers system is essentially used by MISO to allow participants to nominate the FTRs they value the most in the early rounds, a system which MISO believes results in a more equitable allocation of FTRs among the various participants.

Interestingly, for an LSE which “sinks” 44 in the load zones of a Retail Choice State (a state in which there is retail competition), FTRs are defined monthly for peak and off-peak periods and mirror the FTRs that the LSE was originally allocated through the annual FTR allocation for that given month. However, on a monthly basis following each monthly FTR auction, MISO transfers FTRs to mirror the shift in load between market participants under State Retail Choice. This shift is done for equity purposes so as to adjust the FTR allocations for those native load providers who have seen some of their load shift to third-party retailers.

As is the case in the other jurisdictions covered in this Chapter, the revenues obtained from FTR auctions are credited against each TO’s revenue requirement through their TRBA. The annual adjustment to TRBA (projected revenue credits minus the difference between the last year’s projected revenue credits and actual revenue credits) is a dollar amount added onto the TO’s transmission revenue requirement which then forms the basis for calculating the following year’s MISO zonal and drive-out and drive-through rates.

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44 A “sink” represents the location of energy consumption.
6 New England ISO (ISO-NE)

6.1 Introduction

ISO-NE is one of the few North American ISOs to administer a system-wide (postage stamp) transmission access charge. ISO-NE is also different in the way its LMP market design affects access charges. Indeed, unlike most ISOs, ISO-NE allocates congestion revenue primarily to endusers (rather than to the TOs to reduce their access charges).

ISO-NE is a regional transmission organization (RTO) responsible for the reliable operation of New England’s over 33,000-megawatt bulk electric generation and transmission system and ensures a constant availability of electricity for the region. It is also responsible for creating and overseeing open, non-discriminatory, competitive, unbundled markets for energy, capacity, and ancillary services and in doing so has to provide an equitable allocation of costs, benefits and responsibilities among market participants.

ISO-NE has eight load zones for which transmission service is provided through ISO-NE by over fifteen transmission owners. There is no direct correlation between the zones and the transmission providers, as the zones refer to the location based marginal pricing zones used by ISO-NE for load settlement purposes. The ISO-NE calculates energy prices under a locational marginal pricing (LMP) system for each of the zones. These prices are based on generators’ offers, load, and the network’s transmission and operating constraints where each LMP is the sum of three components:

\[ \text{LMP ($/MWh)} = (\text{Energy component} + \text{Loss component}) + \text{Congestion Component} \]

As such, the congestion component of transmission services is recovered through the commodity price just as it is in other jurisdictions with an LMP system such as the NYISO.
6.2 Access to Transmission Services and related charges

ISO-NE provides transmission owners with a host of transmission services depending on the nature of the transmission customer and their transmission needs. These services can generally be grouped in two main categories:

- Pool transmission facilities service (PTF)
- Local transmission service (LNS)

Each service offers a combination of firm and non-firm point-to-point transmission services in addition to short term and long term services.

PTF service, which is priced on a postage stamp basis, allows network customers to use the pool transmission facilities to provide load in New England. PTFs are those facilities rated 69 kV or above that provide parallel path capability to the interconnected bulk power system. They are owned by individual transmission owners, yet operated by ISO-NE through the open access transmission tariff. Transmission customers using this transmission services pay the ISO a charge per kW of reserved capacity based on an annual rate referred to as the Pool PTF rate45.

45 With some exceptions, notably that of service to the New York control area.
The current Pool PTF rates are detailed in Figure 13. As the table suggests, the PTF rate is calculated through a two-stage process, one which focuses on calculating the rate pre-1997 and the other post-1997, with 1997 being the date at which ISO-NE was formed and took over control of transmission operations. The pre 1997 rates are intended to reflect the costs of transmission facilities in service by the end of 1996. The post 1997 rates are intended to reflect the costs of transmission facilities placed in service after 1997. The notable difference in the calculation of these rates is that the cost of new facilities (i.e. placed in service after 1997) is shared evenly based on network load across transmission providers. In other words they are socialized. These two individual rates are then summed up for each transmission owner and subsequently blended into a Pool PTF rate to be paid by all PTF transmission service users.

**Figure 13. ISO-NE transmission service rates**

<table>
<thead>
<tr>
<th>Transmission Provider (PTO)</th>
<th>RNS Rates</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Pre 1997</td>
</tr>
<tr>
<td>$/kW Year</td>
<td></td>
</tr>
<tr>
<td>BECO</td>
<td>14.25</td>
</tr>
<tr>
<td>BH</td>
<td>6.64</td>
</tr>
<tr>
<td>CES</td>
<td>9.82</td>
</tr>
<tr>
<td>CMP</td>
<td>14.88</td>
</tr>
<tr>
<td>NGRID</td>
<td>13.34</td>
</tr>
<tr>
<td>NU</td>
<td>12.73</td>
</tr>
<tr>
<td>UI</td>
<td>14.88</td>
</tr>
<tr>
<td>VT Transco</td>
<td>14.88</td>
</tr>
<tr>
<td>Pool PTF</td>
<td>13.28</td>
</tr>
</tbody>
</table>

*Source: ISO-NE, reflects RNS service which uses the PTF facilities*

The Pool PTF rate in effect at any time is determined annually by ISO-NE based on the information transmission owners provide through their Form 1 filings for the most recent calendar year. The Pool PTF rate is set annually effective as of June 1 in each year. It is calculated as the sum for all transmission owners’ annual revenue requirements plus the forecasted transmission revenue requirements and annual true-ups from previous periods divided by the sum of the coincident monthly peaks of all local networks. The hourly rate is then calculated as the annual Pool PTF rate divided by 8760. It should be noted that revenues associated with short-term point-to-point reservations (less than one year) are credited to the sum of all transmission owners’ revenue requirements. By using a true-up account mechanism, ISO-NE guarantees equal treatment among transmitters with regards to cost recovery. Indeed under its system, the collected charges are allocated to the TOs pro-rata based on their individual shares of the total revenue requirement. If the estimated usage based on ISO-NE’s

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46 Or similar information on the books of transmission owners that are not required to submit a Form 1 filing.
load forecasts is different than the actual usage, the under-recovery or over-recovery of revenue requirements are taken into account in the subsequent year’s revenue requirement assessment through the true-up account.

In contrast to PTF, local transmission service is provided on a point-to-point transmission service basis (over non-PTF transmission facilities). It is typically designed to allow local transmission owners to use their transmission system to efficiently and economically serve their native load. Advance arrangements for local transmission service are obtained via the ISO, but charges for local service are billed by the local transmission owner. The rates for local services are calculated on a cost of service basis for each of the transmission owners in the ISO-NE footprint. The local service rates are calculated pursuant to the OATT using each transmission owner’s costs of providing local service (local service revenue requirement). For instance the local point-to-point charge is calculated as:

Local charge = annual local network revenue requirement divided by load connected to the local network

The local network load is calculated as the monthly transmission system peak minus the coincident peak usage of all firm local point-to-point service customers plus the reserved capacity of all firm local point-to-point service customers.

These local rates vary by owner but typically include a monthly, weekly or daily demand charge calculated based on the owner’s revenue requirement and the customer’s load, in addition to the procurement of ancillary and other related services. Local service in New England is currently provided by 15 transmission owners.

As mentioned earlier, ISO-NE also offers several other transmission services, notably for imports and exports (second category mentioned above). These include:

- **CSC transmission service**: uses the cross sound cable is used to move energy “in to”, “out of” or “through” the New England control area at the NYISO intertie
- **Phase I/II transmission service**: used to move energy “in to”, “out of” or “through” the New England control area at the Hydro Quebec intertie
- **MEPCO transmission service**: used to move energy “in to”, “out of” or “through” the New England control area at the Maritimes intertie

With regards to transmission upgrades and the recovery of their costs, ISO-NE categorizes these in order to determine their treatment. Under such a categorization, elective transmission upgrades, upgrades that only provide local benefits, merchant transmission facilities, and any other localized costs are not “Pool-Supported PTF costs”. In other words, these costs are not socialized to all Pool transmission facilities users through the Pool PTF rate. On the other hand, all regional benefit upgrades for instance are “Pool-Supported PTF costs,” which basically means that they are incorporated into the annual revenue requirements used to derive the Pool PTF rates.
6.3 Linkages between transmission access charges and LMP in ISO-NE

ISO-NE operates a wholesale spot market with LMP where the price at any specific location includes the commodity price, the cost of network losses and that of congestion. As such the congestion costs associated with providing transmission access are reflected in the LMPs. Nevertheless, as is common in most North American RTOs, the revenues generated by congestion, whether directly through congestion rents and payments or indirectly through the sale of transmission rights, are applied to transmission related services. In New England, as is discussed further below, the revenues generated from the sale of financial transmission rights (FTRs) are used to fund transmission upgrades rather than to defray investment costs for existing transmission in addition to reducing the congestion costs of load serving entities.

ISO-NE offers FTRs to those market participants wishing to hedge their congestion costs (manage congestion risk). The FTR capability of the New England transmission system is bought and sold through an auction conducted by the ISO. These auctions occur on a monthly and yearly basis and allow eligible FTR bidders to acquire or FTR holders to sell FTRs.

The ISO is the authority responsible for the implementation of the auction process and for enforcing procedures both for short term and long term auctions. It is interesting to note that the auction schedule generally seeks to coordinate the start and end dates of the long-term FTR auction in New England with those of the long-term FTR auction of neighboring control areas. Prior to any long-term auction, the entire transfer capability of the New England transmission system is made available to support the sale of FTRs. In the long term annual FTR auctions, 50% of the feasible FTRs must be made available. The remaining FTRs are then made available for sale through monthly auctions. The FTRs traded through the auction are unidirectional and specify a capacity in megawatts (MW) to be transported from a point of receipt (where the power is injected onto the New England grid) to a point of delivery (where the power is withdrawn from the New England grid).

For each hour in which congestion exists on the New England transmission system between the receipt and delivery points specified in the FTR, the holder of the FTR is awarded a share of the congestion charges collected for that hour\textsuperscript{47}. The congestion charges are calculated based on the FTR’s quantity and the difference between the congestion components of the day-ahead LMPs at the delivery point and point of receipt as detailed in the formula below:

\textsuperscript{47} Non-PTF external interfaces are excluded from the FTR Auction because flows over those facilities are limited to those with transmission reservations (i.e. there is no congestion) and therefore render moot the need for any FTRs.
The hourly congestion charges (positive or negative) are summed up for each FTR and for each FTR holder on a monthly basis. Revenues generated through the FTR auctions do not directly impact transmission access charges, as is the case in the other US markets studied. In ISO-NE, such revenues are allocated to:

1. entities paying for transmission upgrades; and
2. congestion paying load serving entities (LSEs).

Regarding transmission upgrades, the FTR auction revenues are indeed distributed through “Qualified Upgrade Awards”. These are awarded to entities that pay for transmission upgrades that serve to increase the transfer capability of ISO-NE’s transmission network, making it possible to award additional FTRs in the FTR Auction. Under ISO-NE rules, such transmission upgrades in-service on or after March 1, 1997 may qualify for these Qualified Upgrade Awards. The qualification for these awards depends on the type of upgrade being carried out. For instance, generator interconnection upgrades and elective upgrades qualify whereas those upgrades paid for by the PTF rate do not. Furthermore, auction revenues associated with these awards are distributed to the entities in proportion to their cost responsibility in the entire upgrade project.

The issue of transmission upgrades has been somewhat contentious in New England, notably those upgrades to Pool transmission facilities that are socialized and recovered through the Pool PTF rate. Indeed, there have been several dissenting opinions, notably from the Maine Public Utilities Commission (MPUC) and the Vermont Department of Public Service (VDPS) who claim that their ratepayers are being unfairly allocated the costs of transmission upgrades which predominantly benefit ratepayers in other New England jurisdictions, such as Connecticut for instance.

The revenues generated from the sale of FTRs are also distributed to congestion paying LSEs. The allocation of revenues to LSEs is done through a four stage process:

1. Determine auction revenue rights (ARRs) in megawatts from each generator source node or tie line source external node to each load node
2. Value the ARRs using the clearing prices from the FTR auction
3. Sum the value of the simultaneously feasible ARRs by load zone.
4. Distribute to each ARR holder in the load zone its share of the ARR value allocated to the load zone. The shares are determined based on each ARR holder’s reserved capacity.
It is important to note that regardless of how congestion revenues are allocated, the end result is ultimately the same as that in other jurisdictions that is they serve to reduce transmission access charges. In the long run this congestion revenue distribution will indeed serve to reduce access charges, though indirectly, as LSEs benefiting from these congestion revenues will in turn incur lower costs (as a result of having their congestion costs partially mitigated through auction revenues). These lower costs result in de facto lower transmission access charges to be paid for by transmission customers.
7 New York ISO (NYISO)

7.1 Introduction

The New York ISO’s transmission access charge, referred to as the wholesale transmission service charge (wholesale TSC) is a licensed-plate tariff where each transmission owner has a different tariff for the use of their transmission network. Transmission customers however are obligated to solely pay the rate for the zone where their load is located. These tariffs are administered by the New York Independent System Operator (NYISO) and are derived based on the transmission owners’ revenue requirements for operating and maintaining their transmission systems. These revenue requirements vary yearly depending on cost of service requirements and the revenues generated from congestion rents and their hedging contracts known as transmission congestion contracts (TCCs).

The New York wholesale market is administered by the NYISO has eleven geographical areas (load zones) that are defined by key internal transmission interfaces. The zones are: West (Zone A), Genesee (Zone B), Central (Zone C), North (Zone D), Mohawk Valley (Zone E), Capital (Zone F), Hudson Valley (Zone G), Millwood (Zone H), Dunwoodie (Zone I), New York City (Zone J) and Long Island (Zone K). The zonal delineation illustrated in Figure 14 is used for load settlements where loads pay the zonal energy prices at the point of output. However, these load zones for the large part have different geographical boundaries from the “transmission districts” of the various transmission owners as highlighted in Figure 14.

Wholesale market prices in the NYISO are determined similarly to those in other ISOs, notably in the northeast, whereby the locational based marginal price (LBMP) consists of three settlements:

- Energy Settlement - for energy sold to or purchased from the NYISO

The NYISO was established in 1999 and serves as both the transmission system and market operator for the region formerly encompassed by the New York Power Pool (NYPP). As such, the NYISO operates the electricity spot market (day-ahead and real-time) in addition to coordinating dispatch on the transmission system.

The NYISO’s transmission network spans over 17,000 km and serves over 19 million customers in the state of New York. Grid ownership in the state remains with the incumbent utilities: CH Energy Group, ConEd/O&R, LIPA, NYPA, NYSEG, RG&E and NIMO.

The NYISO transmission grid plays a central role in US Northeast through interconnections with the Hydro-Quebec system in Quebec, the IESO in Ontario, ISO-New England and the PJM interconnection.
• Losses Settlement - for naturally occurring energy losses due to resistance in transmission lines created by energy sales/purchases in the NYISO

• Congestion Settlement - for congestion created/eliminated on the NY Control Area system by energy sales/purchases in the NYISO.

In essence the LBMP includes the energy price, line losses and congestion costs. As such the transmission congestion cost is recovered in the commodity price rather then through transmission charges.

Figure 14. NYISO transmission districts and load zones

Source: NYISO
7.2 Access to Transmission Services and related charges

Transmission access charges or system usage charges (also known as transmission use of system charges (TuOS)), are determined according to NYISO’s Market Administration and Control Area Services Tariff (MACAS). This tariff includes all the relevant tariffs applicable to market participants for services provided by the NYISO. As such, the tariff contains market rules applicable to transmission usage as well as those related to the NYISO’s operation of the energy and capacity markets and provision of ancillary services. The MACAS tariff also includes those charges associated with assuring system reliability (also referred to as “Control Area Services”).

As is the case for all ISOs and RTOs in the US, the terms and conditions governing transmission service are provided for under the entity’s OATT, which is mandated and approved by FERC. The NYISO’s OATT provides for two broad categories of transmission services:

1. Point-to-point transmission service (firm and non-firm)
2. Network service

Firm point-to-point services are available on both a long and a short term basis. Long-term firm point-to-point transmission allows the transmission customer to set the price of its transmission service by fixing the costs associated with its day-ahead congestion rent. As such, customers purchasing firm point-to-point transmission service typically acquire sufficient transmission congestion contracts (TCCs) with the same points of delivery and receipt as the transmission service they have contracted for. This not only ensures that their transmission service is not curtailed but also that they have hedged their potential congestion costs. Short-term firm point-to-point transmission service has the same characteristics as the long-term service with the notable exception that the transmission service price is fixed for a short term. The minimum term for firm service is one hour.

On the other hand, customers purchasing non-firm point-to-point transmission service do not typically hedge against congestion through TCCs due to the nature of their service (i.e. interruptible). Since users of such transmission service only intend to use the transmission system for those intervals when there is no congestion, their (interruptible) service will be curtailed in the event that there is transmission constraints. The term for non-firm service has a minimum of one-hour and a maximum of twenty-four consecutive hours.

The network integration transmission service provided by the NYISO is for those transmission owners who utilize their respective transmission systems to serve their native load customers for select designated-resources (i.e. those resources designated by the ISO to serve native load) within the NYCA. Similar to the provision of firm transmission service, network integration transmission service customers may set the price of their transmission service by purchasing TCCs corresponding to the designated network resources and load. Transmission customers choosing this service will be provided firm transmission service over transmission system from the network resource to the network customer. Furthermore, network integration transmission service...
service can also be used to deliver electricity purchases to network load which originates from non-designated resources, but on an as-available basis only (i.e. when there is no congestion).

As mentioned previously, transmission access charges are calculated on a zonal basis. All transmission access charges are based on a rate component referred to as the wholesale transmission service charge which is determined for each transmission owner. Transmission customers are charged the rate for the transmission district (zone) to which they are transmitting power.

All other transmission services are priced at the wholesale transmission service charge. To determine each of their respective transmission charges, the transmission owners initially develop a revenue requirement for owning and maintaining their transmission system. These revenue requirements typically include elements such as capital costs, returns on and of capital and operating and maintenance expenses (O&M). To these approved revenue requirements are then added the costs for each transmission owner’s pro-rata share of ISO scheduling and dispatch costs and then revenues from TCC auctions, congestion payments and imports or exports are deducted.

\[
\text{Wholesale TSC} = \frac{\left[ (RR + CCC - SR - ECR - CRR - WR) / BU \right]}{12}
\]

Where, RR is the revenue requirement, CCC is the cost of scheduling, system control and dispatch cost, SR is the revenue from TCC auctions, ECR is the TO’s share of net congestion rents, CCR are the received congestion payments, WR the revenues from any external sales (import/export) and BU are the billing units expressed in MWh of throughput.

As the formula above details, the wholesale TSC is calculated by developing the transmission owner’s applicable annual revenue requirement base and dividing it by each owner’s forecasted annual throughput expressed in MWh (billing units). The applicable revenue requirement base is calculated as the transmission owner’s FERC approved revenue requirement, plus any cost associated with system controls and dispatch. This amount is then reduced by any revenues received by transmission owners through the TCC auctions, congestions rents and payments and any import or export service. Each transmission owner is responsible for calculating the total revenue requirement, its cost of scheduling and the billing units component of its TSC charge. The NYISO is responsible for calculating the remaining components based on NYISO data in addition to data provided by the transmission owners. The transmission owner’s are required to calculated and update the TSC on a monthly basis.
Figure 15 provides an illustration of the wholesale TSC calculations for NYISO’s eight transmission districts. The rate column represents the unit rate prior to any crediting and as such the actual rates differ based on the other components of the TSC rate formula. Transmission customers are only charged the TSC of the district in which they are transmitting power (i.e., point at which the energy is consumed or the “sink”). As an example, a transmission customer transmitting power from the Consolidated Edison district to the Niagara Mohawk Power Corporation’s zone will have to pay Niagara Mohawk the approved TSC for that district. Although the power originated in Consolidated Edison’s zone, they need not pay Consolidated Edison’s TSC.

Wheeling service in addition to import and export service are all charged based on the wholesale TSC. For import transactions, a similar process applies to that of transactions within NYCA which is that the customer is charged based on the district to which the import is destined. Exports and wheeling transactions to other jurisdictions except for the ISO-NE\(^4\), are priced based on the TSC of the NYCA transmission district which neighbors the jurisdiction to which the transmission service is destined.

It is worthwhile to note that unlike other jurisdictions, there is no information available to suggest that NYISO will eventually move to a postage-stamp rate design.

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\(^4\) Current tariff provision provide for unconditional reciprocal elimination of charges on exports and wheeling transactions from the New England Control Area to the New York Control Area.
7.3 Linkages between transmission access charges and LMP in NYISO

In the NYISO, market participants have the ability to hedge against congestion costs by purchasing Transmission Congestion Contracts or TCCs which are equivalent to FTRs in other jurisdictions. The TCCs represent a right to collect or obligation to pay congestion rents in the day-ahead market for energy associated with a single MW of transmission between a specified point of injection (POI) and a point of withdrawal (POW). These TCCs are typically made available through seasonal centralized auctions conducted by the NYISO where TCCs are bought or sold. In such auctions, the primary TCC owners, usually the transmission owner or sometimes another transmission customer that has acquired the TCC through the conversion of TCC rights (known as auction allocation rights or AARs), sell these TCCs to entities which in turn become primary TCC holders. The ISO then settles day-ahead congestion rents with the primary holder of each TCC. A primary holder must be one of the following:

(1) a transmission customer that has purchased the TCC in the centralized TCC auction, and that has not resold in that same auction;

(2) a transmission customer that has purchased the TCC in a direct sale with another transmission customer;

(3) the primary owner who has retained the TCC;

(4) primary owners of the TCC that allocated the TCC to certain customers or sold it in the secondary market or sold through a direct sale to an entity other than a customer.

The TCC auction process is designed to maximize the value of TCC awards, based on the bids and transmission line and contingency constraints.

Figure 16. Sample TCC auction result- June 2007

<table>
<thead>
<tr>
<th>POI</th>
<th>POW</th>
<th>TCCs AWARDED</th>
<th>MARKET-CLEARING $/TCC One Month</th>
</tr>
</thead>
<tbody>
<tr>
<td>23552</td>
<td>61762</td>
<td>50</td>
<td>$342.00</td>
</tr>
<tr>
<td>25552</td>
<td>24216</td>
<td>49</td>
<td>$745.00</td>
</tr>
<tr>
<td>61758</td>
<td>61762</td>
<td>43</td>
<td>($2,550.00)</td>
</tr>
<tr>
<td>23552</td>
<td>61762</td>
<td>41</td>
<td>$342.00</td>
</tr>
<tr>
<td>24065</td>
<td>61754</td>
<td>35</td>
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<td>61753</td>
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<td>$3,874.82</td>
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<td>25548</td>
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<td>$43.26</td>
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<td>25557</td>
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<tr>
<td>23531</td>
<td>61761</td>
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<td>$4,147.19</td>
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<td>24053</td>
<td>23760</td>
<td>24</td>
<td>$16.50</td>
</tr>
<tr>
<td>23515</td>
<td>23519</td>
<td>20</td>
<td>($131.81)</td>
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<td>$326.12</td>
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<td>23501</td>
<td>23543</td>
<td>17</td>
<td>($51.36)</td>
</tr>
<tr>
<td>61758</td>
<td>61758</td>
<td>16</td>
<td>($654.41)</td>
</tr>
</tbody>
</table>

Source: NYISO
The NYISO provides for a mechanism that de facto reduces the wholesale TSC component of the transmission usage tariff based on the revenue generated from the various congestion management instruments. Indeed, as the wholesale TSC calculation formula detailed in the previous section suggests, the revenue requirement used to determine the wholesale TSC is reduced by an amount equal to each transmission owner’s net congestion rent revenue and TCC auction revenue. The net auction (sale) revenue is essentially calculated by the ISO as the total revenues generated by each auction (revenues from and payments for the award of TCCs) minus the TCC costs of each transmission owner (payments or charges to holders selling TCCs). Included in the total net auction revenue are those revenues generated from the sale of regular TCCs, grandfathered TCCs and residual TCCs. This revenue is then distributed to the transmission owners by the ISO and serves to reduce each transmission owner’s revenue requirement used in the determination of transmission service charges.
8 PJM

8.1 Introduction

Transmission access charges in PJM Interconnection LLC (PJM) are assessed on a license-plate basis meaning that each zone with the PJM market has its own zonal transmission access rate. The adoption of this rate design can largely be attributed to PJM’s rapid geographical expansion which led to the market having to integrate several new transmission owners.

Indeed, the PJM market has grown steadily over the years. The geographical market served by the original footprint covered the mid-Atlantic area, including most of Pennsylvania, New Jersey, Delaware, Maryland, and District of Columbia. However, over the last five years, the PJM system has expanded to parts of Kentucky, Illinois, Indiana, Michigan, North Carolina, Ohio, Tennessee, Virginia, and West Virginia.

Figure 17 below illustrates the expansion of PJM’s service territory over time.

PJM was formed in 2001. It operates the centralized spot markets for electricity, capacity and ancillary services, and is tasked with maintaining the integrity of the regional power grid.

PJM controls 90,200 km of transmission lines servicing approximately 54 million people through 16 transmitters. The generating capacity in the market is 164,634 MW with a peak demand recorded at 144,644 MW.

The PJM footprint covers 13 states and the Washington DC metropolitan area.

Figure 17. Overview of PJM’s current footprint and its expansion over time

The license-plate design has been subject to numerous discussions in PJM as if and when the market should adopt a postage stamp rate for access to its transmission system. In 1997, FERC’s decision stipulated that the license-plate rate design was to be left in place for five years (until July 2002), at which point PJM was required to file a new proposal for the implementation of a uniform, system-wide rate design. In 2002 however, FERC postponed the change in the PJM rate design and it requested the PJM to re-file a proposal for a new market rate design in January 2005.49

In 2004, FERC addressed the seams issues between PJM and the adjacent MISO market. The regional “through and out” charges (RTOR) on transactions that cross the PJM and MISO borders were eliminated as FERC considered these charges to have a “pancaking” effect on transmission rates and considered them to represent a barrier to efficient wholesale market. However, because the elimination of RTOR caused a revenue shortfall for many cross borders transmitters, FERC ruled that during the transitional period (December 2004-April 2006), defined as the period between the elimination of “through and out” charges and the implementation of a new market rate design, an alternative to RTOR, SECA (Seams-Elimination Cost Adjustment) charges will be put in place. 50

In PJM, SECA charges were imposed as a $/MW-day rate based on customer usage. However, in PJM zone of Duquesne Light (bordering MISO) and in MISO, SECA charges were imposed on suppliers as a monthly charge calculated using the historical load served within a utility service territory. The SECA charges ended in April 2006. Since then, customers that are wheeling power from MISO to PJM pay the zonal price of the PJM zone designated as a sink while the PJM TOs are paid the MISO system wide through and out charge for power transmission sinking in MISO. For transactions other than those between MISO and PJM, these are priced at the PJM Border rate. This Border rate and all other rates associated with transmission services in the PJM market are explained in more detail in the next section of this Chapter.

In response to PJM’s January 31 2005 filing regarding the new market rate design, FERC approved on April 19, 2007 a modified version of the license-plate design. 51 This modified design retains the zonal approach to the rate system with respect to existing transmission facilities; but also introduces a uniform price for costs associated with lines rated at 500 kV or above. This modified license-plate pricing is considered to be a transitory system imposed by FERC until PJM and MISO harmonize their transmission charging designs, which is expected to take place in February 2008, at which point a new rate design will be introduced. Section 8.4 of this Chapter offers the background and more detail on the recent FERC ruling with respect to the postage stamp rate for high voltage transmission.

49 In the PJM Tariff through and out charges defined as charges at the border between the PJM and the adjacent control areas.
51 Docket No. ER04-156-000, Docket No. EL05-121-000, 002 and ER06-1271-003, et al.
8.2 Access to Transmission Services and related charges

Under the license-plate rates design in PJM, each transmission customer pays a rate based on the costs of transmission facilities located in its transmission zone. In PJM, there are fifteen transmission zones mainly served by incumbent TOs (see Figure 18).

![Figure 18. Map of transmission zones in PJM](image)

As mandated by FERC and as is standard across the various US markets covered in this Chapter, the TOs in PJM provide network integration service and point-to-point transmission services (firm and non-firm, long-term and short-term). The transmission access charges for these services are derived from the TO’s annual revenue requirement filings.

Specifically, for each TO, the annual price for network transmission services ($/MW) is the ratio of the TO’s FERC approved net revenue requirement to the annual coincident peak demand recorded in its zone (using the single coincident peak method). The PJM TOs that serve the “non-zone” network load, defined under the PJM OATT as the network zone load outside of the PJM region, charge the “non-zone” price calculated as the sum of all TOs revenue requirements divided by the PJM region’s annual peak demand. Revenues from this transmission service are then distributed by to the individual TOs pro-rata based on their revenue requirement as is further detailed below. The prices for point-to-point services are

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52 Transmission zones in PJM are geographic areas served by an incumbent regulated transmission owner.
53 In MISO the coincident peak demand averaged over the previous 11 months (12 CP) is used for calculation of its zonal prices. In the Order 888 FERC preferable methodology was 12 CP but permitted the RTOs to use alternatives to 12 CP methodology if they are more appropriate.
calculated by dividing the TO’s revenue requirement with its zonal coincident peak demand averaged over the previous 11 months.

These annual prices (known as “demand charges”) for transmission services are than simply divided by the number of months, weeks, days or hours to obtain monthly, weekly, daily or hourly prices for network and point-to-point services in the PJM market.

With the elimination of RTOR and SECA charges, no charge is assessed for sinking load at the border with MISO. However, PJM does assess charges for wheeling services which it defines in its OATT as services that originate and sink at the PJM borders with other control areas. For these services, the PJM customers pay the Border rate, a weighted average of zonal rates for point-to-point transmission services.

The billing practices and revenue distribution for these transmission charges are explained in the sections that follow. Customers of network integration service pay daily demand charges calculated as the customer’s daily peak load contribution coincident with the annual peak demand multiplied by the applicable zonal rate. The zonal rate used is that of the zone in which the load is located. If the load is located outside of the PJM region, the customer’s daily peak contribution is coincident with the non-zone’s annual peak demand (the PJM region peak demand) and the non-zone’s rate (rate of neighboring jurisdiction) is applied. The network transmission customers are subject to congestion charges and charges for losses associated with the energy that they transmit along a specific transmission path. The network service charges are settled monthly and the resulting revenues are distributed to the respective transmission owners based on the ratio of their revenue requirement to the sum of all revenue requirements in the system.

Depending on the delivery zone, prices for network integration service are in the range of $10 - $32/kW-year in PJM. The prices can be adjusted over time based on the standard, FERC mandated, cost-of-service formulas in transmission owners’ filings with FERC.

54 In general, transmission congestion charges are calculated for each transmission user based on the differences in LMPs between the points of receipt and delivery (source and sink). Resulting transmission congestion credits (TCCs) are given to each holder of financial transmission rights (FTRs) as a proportional share of the total TCCs collected for each constrained hour.
The price for a firm point-to-point transmission customer is based on the transmission customer’s reserved capacity multiplied by the applicable zonal rate (see Figure 20) as shown in the formula below:

\[
\text{Price of Firm Point-to-Point Service} = \text{Transmission Service Charge} - \text{Applicable Firm Point-to-Point Transaction Charge Rate} \times \text{Service Contract MW}
\]

Firm point-to-point transmission customers are also responsible for congestion charges and charges for losses associated with transmitting along a specific transmission path. Furthermore, firm point-to-point access charges are billed monthly. The total revenue from these charges is then distributed to each TO based on the ratio of its revenue requirement to the sum of all TOs transmission revenue requirements in the market. The table below illustrates the current rates for point-to-point services.

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55 In general, transmission congestion charges are calculated for each transmission user based on the differences in LMPs between the points of receipt and delivery (source and sink). Resulting transmission congestion credits (TCCs) are given to each holder of financial transmission rights (FTRs) as a proportional share of the total TCCs collected for each constrained hour.
The price for a non-firm point-to-point transmission customer is based on the transmission customer’s reserved capacity (less the capacity curtailed, if applicable) multiplied by the applicable hourly zonal rate (see Figure 20).  

\[
\text{Non-Firm Point-to-Point Service Charge} = \text{Hourly Non-Firm Transmission Service Charge} - \left[\text{Hourly Demand Charge Rate} \times (\text{MWs reserved} - \text{MWs curtailed})\right] - (\text{hourly congestion charge, if congestion charge} > 0)
\]

Transmission customers do not pay for non-firm transmission service with the point of delivery at a MISO interface since expiration of SECA charges.  

\[56\]
\[57\]
\[58\]
Non-firm transmission service customers are not allocated any ARRs in return for paying for this service.\(^{59}\) In order to ensure that there is no over-recovery of revenues for TOs, revenues from non-firm transmission service are allocated to all PJM network customers and firm point-to-point customers in proportion to their monthly demand charges (i.e., revenues collected from the sale of non-firm transmission services reduces the tariffs for those PJM customers paying for firm service).\(^{60}\)

In addition to the above described charges, Commonwealth of Edison Co. (ComEd) and American Electric Power Service (AEP) receive additional revenue from PJM’s recovery of start-up costs charges\(^{61}\) which are socialized across all PJM transmission customers. The RTO start up charge is applied in order to recover costs of transmission enhancement and costs of new facilities incurred by ComEd and AEP prior to their joining the PJM market; costs which ComEd and AEP argued could not have been recovered under the new PJM Tariff without resulting in a sudden (and large) increase in transmission charges to their customers. The target recovery amount is set by PJM (through a settlement process with ComEd and AEP, approved by FERC) for each zone and is divided by the annual peak demand of the zone to which it applies in order to obtain the annual charge paid by all consumers in the PJM market ($1,253,787 kW-year for ComEd and $2,362,185 kW-year for AEP). The RTO start-up charge will be in place until 2014 for ComEd and until 2015 for AEP.\(^{62}\)

The costs of interconnecting new customers (which are connected to the grid below 500 kV) are recovered through the Direct Assignment Facilities (DAF) charges billed to the customer for whom the transmission system needs to be upgraded. A customer is assessed a DAF charge if the transmission “facility” being built by the TO is for the customer’s sole use or benefit. The responsible TO is obligated to expand or upgrade the system and the customer must agree to compensate the TO for any necessary additions to the system. The TO determines the costs and provides them to PJM and in return PJM bills the customer. Details of all such arrangements between the TO and the customer, including the estimation of the investment needed for the system upgrade, are made on case by case basis. In a recent decision (April 19, 2007) FERC stated that the “beneficiary pays” methodology for the system upgrades lacks the detail needed to remove uncertainties for transmission customers in terms of when the system upgrades are needed and how the TOs responsible for the upgrades perform the cost evaluations associated with these. Also, since the present methodology is not included in the PJM Tariff, it does leave

\(^{59}\) Network and firm point-to-point customers do receive ARRs, please see section on “Linkages between transmission access charges and LMP in PJM” of this Chapter.

\(^{60}\) Congestion charges are not part of non-firm transmission service revenue calculations. Also any revenues collected from the so called Transitional Revenue Neutrality Charge are given by transmission providers to Allegheny Power and as such also do not filter into calculation for the non-firm transmission service revenue.

\(^{61}\) FERC Docket Nos. ER03-1335 and ER05-1335-000 et al. respectively

\(^{62}\) This is an example of how other jurisdictions might deal with the issue of integration of new members regarding the impact such integration might have on the members and their customers due to change in transmission access charges.
some room for litigation and as a result, FERC advised PJM to look into this issue further by preparing a methodology for system upgrades that is based on a formula (rather than being decided on a case by case basis) that can be included in the PJM Tariff and made publicly available to all PJM customers.

### 8.3 Linkages between transmission access charges and LMP in PJM

PJM uses locational marginal pricing (LMP) for energy and congestion-related charges for the wholesale electricity market. LMPs reflect marginal energy costs, marginal losses (introduced in PJM as of June of this year), and the marginal cost of congestion at each location. Congestion is priced based on the difference in LMPs between the designated delivery and receipt points (source and sink) of generation chosen by a transmission service customer. In PJM FTRs are acquired through three market mechanisms: an annual FTR auction, a monthly FTR auctions and in the FTR secondary market.

By paying transmission access charges for network and firm services, transmission customers receive Auction Revenue Rights (ARRs) entitling them to receive revenues from the FTR Auction. The FTR revenue is distributed to those with ARRs in proportion to their ARRs’ economic value as measured by the clearing prices of FTR Obligations from each FTR auction round. The revenue left over after the distribution to ARR holders is then used to fund any shortfall in FTR target allocations and is known as Excess Congestion Charges.

### 8.4 New developments for transmission cost allocation and access charges in PJM

In response to FERC’s Order of January 31, 2005, PJM submitted a filing in which it proposed to continue the existing zonal rate design until February 1, 2008. The proceedings that followed that filing resulted in the FERC Administrative Law Judge’s (ALJ) decision to introduce a postage-stamp rate design in PJM without any transitional period preceding it. The new rate design was initially intended to be implemented in April 2006 to coincide with the ending of SECA charges but was ultimately abandoned a result of a recent FERC filing.

FERC ALJ’s principal motivation in introducing a postage-stamp rate was the fact that existing transmission facilities in PJM provide cross-zonal benefits which can not be partitioned and distributed adequately among transmission owners. The ALJ also pointed out that in PJM’s Operational Agreement’s definition of transmission facilities it is explicitly stated that all transmission facilities integrated into the planning and operation of PJM are necessary for regional and interregional operations, and are therefore regional transmission facilities which should be subject to uniform pricing.

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63 If insufficient revenues are collected from the Annual FTR Auction to satisfy ARR Target allocations, then the following will occur: (1) ARR Credits are prorated proportionally, (2) Revenues from the monthly FTR auction are first used to fund any ARR deficiencies in the month, then FTR Target Allocation deficiencies, (3) ARR deficiencies may be funded from any annual excess congestion charges remaining at the end of the planning period.
In response to the ALJ’s decision, PJM pointed out that the allocation methodology for ARRs would have to change with the market design. According to PJM, transmission customers should not receive a greater percentage of ARRs than their share of transmission costs, a scenario PJM believed was plausible under the ARR allocation methodology proposed in the new rate design. In response to PJM concerns, FERC staff argued that the implementation of a postage-stamp rate design and the resulting reallocation of transmission costs would not alter the current ARR/FTR allocation process in PJM or have a negative impact on the wholesale market. FERC staff also argued that any ARR issues could be addressed in a separate proceeding if need be.

A recent FERC decision (which was also referenced in previous sections of this Chapter) overturned the recommendations of the ALJ stating that a switch to a postage-stamp rate design at this point in time would represent an abrupt change for market participants in the PJM market and subsequently cause unacceptable levels of cost-shifting. FERC concluded that the continuation of license-plate design in PJM was efficient and economically feasible. However, in this April 19, 2007 decision FERC did approve a postage stamp rate methodology for new, high voltage transmission, in the belief that such a transmission policy would further promote economic efficiency.

64 FERC - Docket#: EL05-121-000, Order, April 19, 2007