Real Flow
A Preliminary Proposal for a Flow-based Congestion Management System

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Table of Contents

EXECUTIVE SUMMARY .......................................................................................................................... 3

I. WHY REAL FLOW? ................................................................................................................................. 4
   1. GOALS OF A CONGESTION MANAGEMENT SYSTEM (CMS) .......................................................... 4
   2. MARKET DEVELOPMENT AND CONGESTION MANAGEMENT ..................................................... 4
   3. WHAT DO CUSTOMERS WANT? ....................................................................................................... 5
   4. CURRENT CM OPTIONS ................................................................................................................... 5

II. THE REAL FLOW PROPOSAL ......................................................................................................... 7
   1. BASIC ASPECTS ............................................................................................................................... 7
      Transmission Property Rights ........................................................................................................ 7
      Bilateral Forward Markets .............................................................................................................. 9
      Real-Time Balancing Market ...................................................................................................... 10
   2. IMPLEMENTATION ........................................................................................................................... 12
   3. A DAY IN THE LIFE: HOW THE SYSTEM IS OPERATED ............................................................ 17
   4. FUTURE MARKET DEVELOPMENTS ............................................................................................... 21
      Retail Access ................................................................................................................................ 21
      New Generation/Transmission ....................................................................................................... 21
      Seams Issues .................................................................................................................................. 22

III. COMPARISON OF REAL FLOW AND LMP .............................................................................. 23
EXECUTIVE SUMMARY

This is a conceptual proposal for a new, flow-based congestion management system (CMS), Real Flow.\(^1\) This CMS establishes a market for physical transmission property rights (PTRs) that internalizes the physics of the electric grid into market design. The purpose of this CMS is to develop a market for transmission capacity that will foster liquid, competitive wholesale and retail markets and provide locational pricing signals for efficient grid expansion. The CMS is additionally designed to permit use of the existing control area infrastructure in loose pools and to institute a Regional Transmission Organization (RTO) that will coordinate the reliable operation of the grid, but play only a minimal role in market operations. This CMS can also be scaled to operate seamlessly in multiple RTOs across the Eastern Interconnection.

The premise of this CMS is that congestion can be managed in forward markets without RTO intervention. This is accomplished by selecting a set of commercially significant flowgates (CSFs), whose capacities market participants purchase and trade in the form of physical transmission rights (PTRs). Participants trading energy are required to purchase PTRs sufficient to cover based the flow impacts of their transactions on the CSFs. This requirement aligns market activity with grid physics. Market participants are required to submit balanced schedules one day ahead of their use. Changes are permitted until the close of the hourly market, as long as the changes have the required physical transmission rights and therefore create no additional congestion. Scheduling in this fashion ensures that, in the absence of unforeseen system outages, congestion will be managed by market participants themselves.

Real Flow permits commercial entities to operate exchanges for energy, transmission and ancillary services within which market participants will trade. The RTO will continuously exchange information with the exchanges to ensure that products traded align with physical system limitations.

The RTO will accept schedules until the markets close and then perform a coordinated dispatch with control areas. The RTO will operate a real-time balancing market, in which it will develop imbalance prices on a locational basis using ancillary service and balancing energy bids submitted by market participants.

This paper describes the design of Real Flow, basic implementation details, and the advantages of Real Flow over other CMSs. Section I describes the objectives of market-based congestion management and the impacts of CMSs on wholesale market development. Section II discusses the design of Real Flow. Section III contrasts Real Flow and the nodal or location-based marginal pricing (LMP) approach in terms of methodology and the objectives of congestion management.

\(^1\) This CMS creates a commercial model based on an approximation of the physical transmission system. This proposal contains contributions, both in concept and material, from Automated Power Exchange (APX).
I. WHY Real Flow?

1. Goals of a Congestion Management System (CMS)

Congestion reflects the scarcity of transmission resources in a grid. A congestion management scheme has several purposes. In the immediate term, transmission flows must be adjusted to protect the integrity and security of the transmission system. This requires a viable operational plan in anticipation of such occurrences, with clear rules for their observance. As with any limited resource, the market seeks to achieve the following short-term objectives:

- Allocate the resource to users who value it most;
- Allow transmission users to express their full valuation of the resource.

In the longer term, if demand continues to outstrip supply, the market should provide incentives to build the least expensive generation or transmission in the right location to alleviate the scarcity.

Finally, any new CMS would need to be implemented within the design objectives of an RTO, including cost-effectiveness, timing, and efficiency. Thus, the administrative costs of instituting and operating markets need to be considered.


The overarching objective of CMS should be to reduce total costs to serve consumers in the long run, including the long-term costs of operating and expanding the physical grid to satisfy demand and demand growth. Since the CMS impacts price signals, it is inherently tied to the markets for wholesale energy and transmission capacity. The choice of any CMS will therefore affect the market in ways that go beyond congestion management.

- To different degrees, all the CM options will affect the characteristics of today's bilateral trading, because of the introduction of locational price differences. Bilateral trading is an integral and vital component of any well-functioning commodity market. It is therefore critical that any new CM scheme facilitate fully a bilateral market to thrive.

- Retail competition is an inevitable next step in several parts of the country, particularly in the Southwest Power Pool and parts of the Midwest (e.g., Illinois), where participants have committed to this direction. Thus, the design of a new CM scheme needs not only to anticipate and plan for changes that may result from retail competition, it must also ensure that the resulting system is simple and practicable enough to permit full-scale retail choice. Retail competition by definition will demand increased trading, as new entities come forward to serve retail customers. New entrants face substantial risks and challenges. Simplicity and advance price certainty will be essential if the market is to function for such unsophisticated users.
• In public policy, economic efficiency should be checked by considerations of equity. CM schemes may internalize some equity considerations, such as allocating congestion costs to the users of scarce resources, rather than to all consumers. Other less obvious equity considerations also arise with locational CM schemes. For example, prices in locational CM schemes are designed to reflect properties of the physical grid. Nevertheless, requiring consumers to pay different prices due to grid properties that are independent of their usage patterns or out of their control is not likely to be perceived as equitable.

3. What do customers want?
Since wholesale and eventually retail consumers are the ultimate beneficiaries, the design of a CMS should incorporate their preferences. For the most part, their preferences coincide with the goals discussed above:
• Flexibility
• Delivery Certainty
• Price certainty
• Simplicity
• Low delivery price
• Elimination of Transmission Loading Relief (TLRs) except in emergencies

4. Current CM Options
Transmission capacity is sold based on contract paths pursuant to the rules of The Federal Energy Regulatory Commission’s (FERC’s) Order No. 888 and No. 889. Congestion management is currently handled primarily through TLR procedures. The drawbacks with the current method of congestion management are twofold: (a) TLR procedures handle excess demand for resources through a quantity rationing process, rather than a market or price rationing process, where users are not allowed to express the value they place on access to the scarce resource; and (b) contract path-based trading ignores the physical realities of power flow, and does not efficiently prevent congestion in forward markets, sometimes even causing congestion due to loop flows. As a result, market participants presently have little certainty of delivery.

Current practice is widely recognized as economically inefficient. The following market-based, locational CM alternatives have been proposed and implemented in different markets across the US and in other countries (See Section III for a detailed comparison of these systems):

• Nodal Pricing or Location-based Marginal Pricing (LMP): This method resolves congestion by pricing energy at every node on the system based on the marginal cost of energy at that node. Market participants bid periodically into a centralized pool (day-ahead, hour-ahead), and the RTO calculates nodal prices based on an optimal power flow model that takes as inputs participant bids and the state of the transmission system. Participants may hedge their exposure to congestion risk by purchasing financial transmission rights (FTRs) between any two points within the RTO's system. Prices are calculated after-the-fact (ex-post): Purchasers have only
uncertain advance knowledge of their transaction’s value. LMP has been implemented in New York, PJM, and is under development in NEPOOL. LMP has also been implemented in Argentina, Chile, Peru and other countries. The key drawbacks associated with this system are its complexity, the lack of price certainty, high cost, and low liquidity in the forward market.

- **Zonal Pricing** – This model is most appropriate for radial systems, which do not exhibit significant loop flows. It is characterized by physical property rights defined for select interfaces between zones and aggregated locational prices within zones. Dispatch may or may not be centralized. In the presence of loop flows, this approach must be combined with the flow-based approach described below. A variation of this model has been implemented in California and proposed in the Mountain West ISA. This approach involves some approximations in overlaying a simple commercial model over the physical system, which results in some intra-zonal congestion being allocated generally in an uplift charge.

- **Flow-based/Zonal** - The premise of this approach is that congestion can be managed in forward markets without RTO intervention. This is accomplished by selecting a set of commercially significant flowgates (CSFs), whose capacities market participants purchase and trade in the form of PTRs. The RTO runs a real-time balancing market and coordinates dispatch with control areas. The RTO is divided into zones based on a clustering of nodes that have similar flow impacts on the CSFs. The RTO calculates zonal prices in the balancing market. These zones provide price simplicity. This approach is being implemented in ERCOT, and has been proposed in the Northwest RTO and Desert Star in the west.

Real Flow is a new flow-based CMS designed specifically for larger, 'loose' pools with multiple control areas. It is principally based on the establishment of physical, tradable property rights, minimal RTO involvement in markets, and the preservation of some or all existing control areas. The methodology and design of Real Flow is discussed below.
II. The Real Flow Proposal

This section describes the fundamentals of Real Flow and overviews its implementation. Part 1 describes the basic aspects of the proposal, including transmission property rights, forward markets, the role of the RTO, and the real-time market. Part 2 discusses further implementation details of the above aspects. Part 3 describes the basic day-to-day operations of the market, and Part 4 discusses how Real Flow handles anticipated market developments, such as retail access.

The institutional and market structure is shown in Figure 1. Market participants trade energy, transmission, ancillary services and balancing energy in commercially run forward exchanges that operate on a continuous basis. Congestion is self-managed in the forward market by virtue of the physical transmission rights (PTR) that limit the quantity of rights initially auctioned. The RTO constantly exchanges information with the market. The forward markets close at a pre-determined time (hour-ahead, for discussion purposes) at which time the RTO accepts final schedules from the exchanges and market participants and coordinates with control areas to balance energy and preserve the reliability of the system. The RTO itself has no role in forward markets beyond the exchange of information.

![Figure 1: Real Flow Market Structure](image)

1. Basic Aspects

Transmission Property Rights

Any CMS has to define tradable transmission rights. Such rights provide delivery certainty and protect them from congestion. Real Flow defines physical, tradable transmission rights (PTRs). These rights will be defined for a finite set of flowgates within and on the seams of an RTO. The relevant flowgates will be selected during the
design of the CMS and reevaluated before each primary auction. PTRs give their purchaser or owner the right to a fixed quantity of transfer capability (MW) across a flowgate for all hours within period. Participants in the market are thus able to secure PTRs of known quantity and at a known price before committing to a transaction. Their physical integrity gives market participants certainty for scheduling transactions. However, holders of PTRs will not have the ability to withhold those rights as a means to influence market prices. If a holder of a PTR has not scheduled transmission for the full quantity at a pre-specified time prior to real-time, the RTO will recall and resell unscheduled transfer capability to other customers.

**PTR Markets**: PTR markets will have a well-defined set of PTRs traded continuously. As a result, market participants should have a highly liquid and unconstrained market in which to trade PTRs. By contrast, financial transmission rights (FTRs), which are part of nodal CMS schemes, do not provide the same level of liquidity because the individual products - point-to-point rights for all combinations of nodes - are numerous and idiosyncratic. Secondly, because FTRs are defined as point to point, the intervention of the RTO is required for any reconfiguration of the rights to meet changing needs. Further, the link between the financial market and physical outcome under a purely financial right model is tenuous at best. Leaving aside the lack of liquidity, the two-settlement systems used with FTRs results in strategic bidding for the day-ahead settlement that produces an operational plan bearing no resemblance to the actual real-time dispatch. As a result, the financial market is unable to make a good projection of physical outcomes.

In order to create a primary market for PTRs, the RTO will first establish a set of explicit rights and then auction those rights to market participants. Market participants who acquire PTRs from the RTO in the “primary” PTR market can use them to meet their requirements. In addition, during any period when they do not need all of those PTRs to meet their own requirements, they will have the ability to sell them to other parties. This is referred to as the “secondary” PTR market.

The secondary PTR market will not be administered by the RTO. Rather, it will be administered by one or more independent commercial entities, such as the Automated Power Exchange (APX). The RTO will have a supervisory role over the PTR markets.

**Defining PTRs**: The first step in the implementation of this CMS is the selection of CSFs. This determination should be based on comprehensive load flow analysis and operational experience to determine most likely patterns of congestion and an economic analysis to determine the commercial significance in the marketplace of these congestion patterns. CSFs may be added and subtracted over time to meet stakeholders' needs as the grid evolves.

Since PTRs will be traded on each CSF individually, the PTRs must not exceed the capacity that can simultaneously be delivered on all elements of the transmission system. Thus, the RTO will determine PTR capacities based on simultaneously feasible flow.
limitations.\textsuperscript{2} Since these limits vary over time, the RTO will release incremental capacity seasonally. (See Implementation below for further details).

**Purchasing PTRs:** Real Flow recognizes network flows in electric transmission and aligns PTR purchases with those flow patterns. Transactions between any two points on the grid will have to supported by PTRs on all the CSFs that are materially affected by the transaction. The measure of the required PTRs is a metric called the Power Transfer Distribution Factor (PTDF), which is identical to the PTDFs that the North American Electric Reliability Counsel (NERC) calculates today as part of the Transmission Loading Relief (TLR) procedures.

The PTDF is a property of a transaction point of injection (POI), a point of withdrawal (POW) and a particular flowgate. Every transaction has a PTDF on every CSF. For example, if a one MW transaction from A to B will cause a flow of 0.2 MW on 'C', it will have a PTDF of 0.2 on a CSF 'C'. A market participant will have to purchase PTRs equivalent to the PTDFs on all the CSFs that are impacted by it. Aggregation of points with similar PTDFs provides for market liquidity.

In the primary market the PTRs for each CSF will be sold individually. In the secondary market it is most likely that the PTRs will be grouped based on purchaser requests to the exchanges so as to represent the needed flowgate transfer capability for common sets of transactions. The purchasing process can thus be automated. Rights for transactions can be sold as 'packages' and market participants can maintain and trade portfolios of transmission rights with ease and without necessarily needing detailed knowledge of purchase requirements for every transaction.

### Bilateral Forward Markets

One important characteristic of Real Flow is that one or more independent exchanges can exist for continuous trading of energy, transmission capacity and ancillary services. The effect of these independent markets will be that RTOs will not need to intervene in or interfere with the market. Prices for tradable products will be set through series of bilateral transactions. Prices are known in advance and price discovery is continuous and uninterrupted up until real-time. The creation of a well-defined, small set of transmission products (the CSFs) results in a “common currency,” which, in turn, produces liquidity, market for transmission and, by extension, for energy. Liquidity produces price certainty.

The RTO will post PTR requirements for all transaction pairs in a PTDF matrix to the exchanges. Any participant can calculate PTR requirements for any transaction by simple algebraic calculation using this matrix. Participants in the forward energy market will be required to submit balanced (supply and demand) schedules, along with necessary PTRs associated with every scheduled transaction. The exchanges will be the source of price information needed by market participants to value transmission. The software of the exchanges will provide the ability to obtain bid/offer prices for any given point of

\textsuperscript{2} This is identical to the simultaneous rating process employed in the Western Systems Coordinating Council (WSCC).
injection and withdrawal from the system. One or more exchanges for transmission will exist that will provide a secondary market for PTRs. The RTO will run periodic auctions for incremental capacity. The transmission exchange will post currently traded prices for all CSFs. Participants purchase their loss and reserve requirements in the ancillary market.

All these independent exchanges will not participate in the market and therefore will be no more than “honest brokers”.

**Locational Energy Prices:** In a liquid market the locational differences in energy prices will correlate directly to the value of the distribution factor-based transmission paths between any two locations, as shown in Figure 2 below. Thus, energy at location A (in Figure 2) would trade a $5 less than energy traded at location B (in Figure 2). POI-POW pairs that do not have flow impacts on CSFs will trade at the same price.

**Figure 2: Real Flow Locational Energy Prices in Forward Markets**

```
  Flowgate 1
(10% x $10)

  Flowgate 2
(20% x $20)

A 5 7

Flow A -> B = .1 x $10 + .2 x $20 = $5
```

**Real-Time Balancing Market**

With Real Flow, the RTO will run a single real-time balancing market within the hour once the forward markets have closed. This market will be a “residual market,” including a very small percentage of overall transactions. It will permit redispatch to meet unforeseen circumstances, such as generator or line outage, or unexpected load. Market participants will submit supplemental energy incremental (“inc”) and decremental (“dec”) bids to the RTO. The RTO will use these bids to clear the balancing market on a region-wide basis in real time. The RTO will alleviate constraints through redispatch and counteract imbalances simultaneously across the RTO. Redispatch to alleviate any constraints on the system at points other than on CSFs will be added to the cost of operating the system. The RTO will pro-rate PTRs on CSFs in the event of real-time

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3 The selection of CSFs will ensure that this cost is low. CSFs will be added if this is not the case.
constraints on CSFs due to unexpected outages. The RTO will clear imbalances on the basis of marginal prices calculated at constrained locations within the grid.

**Real-Time Control and Dispatch Function**

The RTO will operate a coordinated, hierarchical control and dispatch function with existing control areas so as to use some of their switching functions and also utilize their existing control, monitoring and metering systems. This means that the control areas will retain some functions and relinquish others to the RTO. For instance, regulation and voltage control can remain the responsibility of existing control areas under direction of the RTO exercising a coordinating role. The specific control strategy adopted will depend upon existing capabilities and cost of implementation in a given RTO. Responsibility for other of the ancillary services, such as black start, will be coordinated by the RTO, but performed where it is most efficient.

**RTO Function**

The RTO will have complete responsibility for reliability as the Security Coordinator. It will coordinate the deployment of ancillary services and serve as the responsible ancillary service provider of last resort (though specific physical responsibilities may be assigned to individual control areas). The control areas will serve as agents of the RTO, and will perform their functions as directed by the RTO to maintain reliability of the system.

The functions of the RTO can be summarized as follows:

- Manage transmission capacity rights on CSFs, including calculation of and posting of TTC, ATC, releasing capacity in primary auctions, and posting PTR transaction requirements.
- Run a single, real-time energy balancing market, including managing a balancing energy stack, performing redispatch and coordinating control area-level dispatch in accordance with redispatch requirements. The RTO will only curtail individual schedules if no other action can maintain reliable system operation.
- Receive and account for balanced schedules from commercial exchanges, scheduling coordinators and individual market participants.
- Forecast RTO load and post resulting ancillary service (regulation and reserve) and loss requirements.

Unlike the system operator in a centralized pool, the RTO will not:

- Run and/or manage the forward energy markets.
- Take over all functional responsibilities of control areas, including transmission system monitoring and control, metering and switching functions.
- Operate a forward ancillary services market for reserves and regulation.
2. Implementation

**PTR Markets**
Defining of CSFs and their purchase requirements using PTDFs provides a logical and simple method for linking commercial activities in forward markets to the physics of the electric grid. The nearly static nature of PTDFs enables trading of CSFs without requiring market participants to address the micro operational complexities of the electric grid operation.

Power Transfer Distribution Factors (PTDFs)⁴
PTDFs are functions of network impedance. They are for the most part static, and change if at all, predominantly in response to physical changes in the transmission system, and in rare circumstances, from changes in levels of generation or load. The primary source of changes to PTDFs is major line outages. These outages are random, and generally short-lived. Outages due to planned maintenance are known well in advance, and PTDFs can be modified with prior notice. Other operational changes, such as changes in dispatch, flows, and load variations have no impact on PTDFs. New generation only affects PTDF to the extent that new transmission is built. These changes along with new transmission construction are known well in advance of the time they are energized. The PTDFs will be modified with prior notice for such changes. Alterations to flow control devices, such as phase shifter settings, have a negligible impact on PTDFs. Table 1 below summarizes the various factors impacting PTDFs.

Distribution factors theoretically can vary by modest amounts on an hourly basis. To insulate the market from the uncertainty associated with these minor changes, the distribution factors can safely be assumed to be constant within seasons. CSF capacities should therefore be recalculated seasonally to account for the outage of generation units during the maintenance season, which for stability reasons may alter CSF transfer capabilities. Discrepancies between schedules and rights in real time can be resolved in the balancing market and the costs allocated back to imbalances.

<table>
<thead>
<tr>
<th>System Change</th>
<th>Impact on PTDFs</th>
<th>Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line Outage</td>
<td>Small</td>
<td>Random</td>
</tr>
<tr>
<td>New Generator/Transmission</td>
<td>Small</td>
<td>Random</td>
</tr>
<tr>
<td>Phase Shifter Adjustment</td>
<td>Negligible</td>
<td>Random</td>
</tr>
<tr>
<td>Change in dispatch</td>
<td>None</td>
<td>Constant</td>
</tr>
<tr>
<td>Load variations</td>
<td>None</td>
<td>Constant</td>
</tr>
</tbody>
</table>

⁴ Note that PTDFs calculated by NERC are strictly control area-to-control area. That is, the flow impacts on flowgates due to a transaction from one control area (multiple generators) to another control area (multiple loads). Although this document refers to PTDFs due to their familiarity in the industry, Real Flow may use generation shift factors, which are flow impacts of point-to-point transactions.
Defining PTRs
The selection of commercially significant flowgates will require engineering and economic analysis at the design stage to prioritize the significance of potentially congested flowgates on the system. The process for selecting CSFs for release into the market place should be as follows:

- Identify all historically constrained transmission flowgates.
- Project competitive wholesale market simulation forward three years based on proposed generation projects and projected load growth to identify other potentially congested transmission flowgates and project the congestion values for the interfaces from projected shadow prices (simulation result) on all the identified interfaces.
- Rank the identified interfaces based on the projected commercial cost of congestion.
- Work with stakeholders to develop a threshold valuation of "commercial significance."
- Select the set of flowgate capacity for release into the market as CSFs based on this threshold.
- Determine the deminimus terms for the PTDF matrix to eliminate the need to purchase fractional MW of capacity on the CSFs.

The number of resulting CSFs is likely to be small. However, transactions will not be made more complicated by the number of CSFs, since transaction costs associated with purchasing PTRs do not scale with the number of CSFs. It is anticipated that packages of PTRs will be made available in the secondary market for transactions between known POIs and POWs.

This analytical approach will identify a comprehensive set of potentially constrained flowgates, and allow for a transparent and interactive decision-making process in which stakeholders can quickly develop a sense of the commercial simplicity most appropriate for the system.

Defining PTR Capacities
There will likely be several possible combinations of simultaneously feasible capacities that can be offered in the market, some of which may be available only under certain conditions. The RTO has several options for releasing capacity in primary markets. The RTO may release the least simultaneously feasible capacity - in Figure 3, represented by $x'$ and $y'$ and release incremental capacity into the market as operational conditions become more certain. Alternatively, the RTO may release the maximum non-simultaneous capacity ($x$ and $y$ in Figure 2) and buy back capacity as required. Because limits vary seasonally, PTRs will be made available in the primary auction on a seasonal basis. For CSFs that have no simultaneous limits, capacity will be sold based on the lower of their Thermal limit, Voltage Limit and Stability Limit.

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5 This can be done using a market simulation tool, such as GE MAPS, which models the transmission system in the Eastern Interconnect. GE MAPS assumes perfect competition and marginal cost-based dispatch from generators and can incorporate demand bids.
Prior to conducting auctions, the RTO will award PTRs to existing contracts. Stakeholders can choose to offer native load PTRs. In the event native load do not get PTRs and participate in the auction, they will receive a reduction in their access charges from the application of auction revenues to the transmission revenue requirements of transmission owners.

The RTO will auction PTRs on all CSFs periodically, e.g., once per year, for capacity available on the existing system. The auction will result in a single clearing price for each category of PTR on each interface, (by season and on/off peak period.) All successful bidders for a primary PTR on a given interface for a given period will pay the same clearing price. The auctions will sell PTRs going out several years, but all rights will be valid for three months, or a season. Thus, a customer desiring PTRs on a particular CSF for two years would bid into four (2 seasons for 2 years) or eight (4 trimesters for 2 years) auctions for that CSF.

There are several reasons for holding annual auctions of this form. First, it gives market participants the opportunity to buy PTRs and get the equivalent of long-term firm transmission service, as defined by FERC. Second, it enables the RTO to re-determine the maximum level of PTRs based on changes in market conditions as well as physical grid changes. This reallocation serves as a dynamic market mechanism to help ensure nondiscriminatory open access and allows market participants to adjust their PTR holdings according to their changing needs.

Conducting a PTR auction is the most economically efficient method of allocating transfer capability between market areas. Those who place the highest value on the guarantee of firm service across CFRs will secure PTRs. This approach produces the maximum level of revenue (congestion rent) which is then applied to reduce the fixed cost of transmission access. It also sends market signals in a forward-looking fashion, and not after-the-fact.
Native Load and Auction Revenues

The revenues from PTR auctions will be returned to transmission service customers in the form of reduced access charges. These revenues will pay down the transmission owner revenue requirements. This revenue crediting will mitigate any increased costs faced by native load due to implementation of the CMS. The revenue will be calculated and applied on an annual basis. This reduction can be passed on to consumers on an annual basis in the form of a rate adjustment clause in transmission owners' rate filings.

The decision to award native load PTRs needs be made under any adopted CMS. Either way, native load customers will be able to hedge themselves against future congestion without an increase in their total costs. If they are awarded PTRs, they will have a hedge against congestion, and will still receive some reduction in access charges from PTR auctions to other market participants. If they do participate in an auction, they will have an incentive to hedge their transmission risk, and should be willing to bid for the PTRs as much as the anticipated increase in their energy costs in the absence of PTRs. If they win an auction, they will hedge themselves but get back the money paid in the auction. If other market participants win the auction, they will face congestion risk, but still see a net decrease in costs, because the decrease in their access charges (equivalent to the winning bids) will exceed their congestion-related energy costs, (corresponding to their bids). Finally, if their perceived value of risk mitigation changes, they can always sell their PTRs in the liquid, secondary market.

In the long run, in the interest of maintaining a level playing field, this paydown to native load can be phased out and applied to all customers in the system on an average basis.

Purchasing PTRs

Market participants will purchase PTRs based on the requirements of their energy transactions. Participants may purchase PTRs independent of associated energy transactions so that they have the flexibility to acquire their necessary resources up until real-time. In order to discourage hoarding, PTRs will be subject to a ‘use it or lose it’ rule. Any PTRs not scheduled with an energy transaction by the time trading in the forward market closes will revert to the RTO without compensation to the holder so as to encourage primary rights holders to release unused capacity to the secondary market. This means that PTRs would have no value once the forward market closes, therefore they could not be held as a strictly financial instrument, unless they were actually being used to facilitate a transaction. Market participants holding unneeded PTRs would be free to sell them prior to the closing of the forward market.

Implementation Requirements (RTO and Control Area)

With Real Flow, the administrative operating costs for the RTO likely should be lower than with a centralized pool. The initial capital costs will be less as there will be no need to replace all of the monitoring, communication and scheduling systems currently in use with a totally new system as was done in California. While California combined only 3
systems, RTOs under discussion today could require the collapsing of 15 or more control areas. The development of hierarchical control logic based on uniform (and limited) dynamic control information flows between the existing control areas and the RTO will allow for change and aggregation in control structure to evolve over time, as systems require replacement. The initial retention of control areas and some of their functions will ease the transition to Real Flow and make it possible to expedite implementation. The decision to combine control functions can be made as systems evolve and new equipment investments are made.

The following systems and software will have to be developed for the RTO to:6

- Communicate to control areas to receive aggregated system state, resource requests and control signals and sending dynamic schedules to the control areas.
- Redispatch and stack manage and balancing and ancillary services.
- Communicate with transmission, energy and ancillary services exchanges.
- Communication with other RTOs.
- Settlements.
- Forecast and model load.

Any costs associated with the establishment of the independent forward market exchanges would be born by the developers of those exchanges.

Notably, most of the foregoing communication and software systems would be required under any system of congestion management. Costs avoided by the Real Flow model but which are incurred under a centralized pool, include:

- Centralization of all switching, metering and data acquisition systems from control areas.
- Pooling of institutional structures across RTO.
- Staff re-training and relocation required in the establishment of a single control system.

The reduction of indirect costs avoided by implementing Real Flow cannot be overemphasized. With the implementation of a centralized pool structure, all market participants need to climb a steep learning curve to understand and participate effectively in a centralized pool market structure. Suppliers who have made purchasing decisions based on bilateral contracts will have to learn to collapse their complex cost functions into a single set of bids. Any lack of sophistication in bidding strategies will disadvantage many market participants. The Real Flow structure, on the other hand, is an extension of current practices to a much more reliable, market-oriented transmission construct.

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6 This is a non-exhaustive list, but highlights the types of information flows and the physical resource requirements that these entail.
3. A Day in the Life: How the system is operated

The following outline brings together, at a basic level, the various aspects of Real Flow into the actual day-to-day workings of the RTO, the market and market participants. Figures 4-7 describe the information flow between the markets, the RTO and control areas at different time intervals.

**DAY-AHEAD**

**Figure 4: Information Flow - Scheduling (Day-Ahead)**

- **RTO Role:**
  - Receives and verify schedules from market participants, including appropriate PTRs, ancillary and loss requirements.
  - Calculates distribution factors and loading on CSFs based on aggregated system state data provided by control areas.
  - Releases unused capacity and arranges any necessary buy-back based on discrepancies between schedule results (including counter-flow effects) and CSF capacities. Calculates and transmits revised TTC and ATC data to markets.
  - Calculates load forecast and posts updated ancillary service and loss requirements in the exchanges, (for e.g., if short by a significant margin).
  - Develops operating plans for the day with control areas, including determining the balancing energy stacks, and decides which resources to ramp based on cost of resources in stacks (for balancing, reserves and regulation).
  - Based on balanced schedules, determines if any significant congestion exists in the remaining (non-CSF) system due to unexpected outages. Develops
preliminary redispatch plan for next day with ancillary service stacks, if necessary.

- **Market Exchanges' Role:**
  - Receive and post updated TTC and ATC information from the RTO.
  - Receive and post updated PTR requirements (if any).
  - Verify and send schedules to the RTO.
  - Continuously facilitate trades between market participants for all tradable products.
  - Post currently traded prices for all products, including hub prices for energy.

- **Market Participants' Role:**
  - Submit schedules for portfolio of energy contracts, with related PTRs, ancillary service purchases and related losses.
  - Calculate and submit desired inc and dec bids from generation portfolios.

**ADJUSTMENTS (DAY-OF)**

![Information Flow - Adjustments (Day-of)](image)

- **RTO Role:**
  - Receives and incorporates continuous adjustments to schedules submitted by participants.
  - In the event of sudden but sustained losses in CSF capacity, derate and reallocate PTRs (pro-rata) among rights holders.
  - Procures any deficient ancillary services using call contracts in the ancillary exchange.
• **Market Exchanges' Role:**
  • Send final, balanced schedules to the RTO hour-ahead for energy, PTRs and ancillary services.

• **Market Participants' Role:**
  • Perform adjustment trades through independent exchanges to manage last-minute updates to load portfolio (for e.g., based on weather-sensitive load profiles), trade resulting surpluses/deficits, finalize supply portfolio (for e.g., based on hydro conditions, daily oil prices, etc.) and update resulting schedules on a continuous basis up to hour-ahead.
  • Update and submit adjustments to balanced schedules, PTR and ancillary service and loss purchases.

**REAL-TIME (HOUR-OF)**

Figure 6: Information Flow - Real-Time (Hour-of)

- **RTO Role:**
  • Receives and responds to energy needs from control areas, using redispatch procedures. Issues orders to ramp resources within a control area, or create an inter-control area dynamic schedule and transmit to each applicable control area, thereby ensuring efficient coordination between control areas.
  • Clears any minor congestion on the system on (“intra-flowgate”) using the ancillary service stacks.
• **Market Exchanges' Role:**
  - None.

• **Market Participants' Role:**
  - None.

**SETTLEMENT (AFTER-THE-FACT)**

Figure 7: Information Flow - Settlement (After-the-fact)

- **RTO Role:**
  - Receives ex-post system state data, including metered load, transmission and generation availability and determine imbalances relative to schedules.
  - Calculates locational, grid-wide marginal costs (clearing prices) of balancing based on supplemental energy utilized taking into account any intra-flowgate congestion— (under normal conditions this will be one single price in the absence of real-time congestion).
  - Collects imbalance payments from Market Participants, calculates and collects costs for resolving intra-flowgate congestion.

- **Market Exchanges' Role:**
  - Receive imbalance dues from RTO for all market participants and facilitate imbalance trades in exchange, transfer imbalance payments to the RTO.

- **Market Participants' Role:**
  - Receive imbalance dues
  - Trade imbalances in exchange with other Market Participants, pay out net deficiency (if any) to the RTO
4. Future Market Developments

Any RTO must anticipate future market developments when making a decision to adopt a new CMS. These include at least the impending adoption of retail choice by states within the RTO, future generation and transmission investments, and the compatibility of the adopted CMS with CMSs adopted by neighboring RTOs. Real Flow offers considerable advantages over other approaches in anticipating these issues.

Retail Access

Two important developments brought by retail competition will impact the decision criteria for selecting a congestion management scheme: a) The creation of a new set of market players, retail aggregators, who will face little understood (poorly metered) and constantly varying load profiles; b) Increase in the volume of and pattern of trading, particularly across control areas and in and out of the RTO.

The value of transparency and therefore simplicity in light of these considerations cannot be over-emphasized. Complexity will impede retail development. Retail aggregators will likely have dynamic portfolios (supply and demand) that can change on a daily basis. The complexity of a financial hedging system (FTRs) with hundreds of nodes and potentially thousands of node-to-node combinations will act to stifle the flexibility of the retail market as it minimizes the liquidity at every delivery point in the network. In such circumstances, liquidity and price certainty in forward markets for energy and transmission capacity are vital. The physical rights approach and ex-ante price characteristics of Real Flow will provide both these characteristics.

The potential change and increases in flow patterns will influence the selection of flowgates. The flowgate selection approach proposed above, because it reflects the expectations, and encourages the participation, of players in the commercial market, will identify likely future patterns of congestion. This market-driven process will provide information for expected trading across RTOs within the interconnections and thereby provide greater stability upon which to base wholesale to retail transactions. Given the obvious limitations in predicting congestion, the more important characteristic of Real Flow is that commercially significant flowgates can be redefined over time as congestion patterns change.

New Generation/Transmission

Capital investments in the grid that relieve congestion or add system capacity need to be awarded the operational rights to the capacity they create in order to discourage free rider problems and create incentives for new investment.

Real Flow provides locational price signals to Market Participants to invest in generation and transmission, since energy prices in different parts of the grid will reflect the value of transmission, expressed in the required flowgate rights, to get from one region to the next.
Under the REAL Flow paradigm, the rights obtained by an expanding party can be defined in terms of the capacity added to a CSF and sold forward to parties who need long term rights and are willing to fund construction. For instance, a party wishing to build a remote resource typically needs long term transmission rights to finance its generation project. Unlike the physical certainty that can be associated with flow gate capacity determinations, the value of a financial right will vary with market prices and changes in system dispatch patterns. The definition of forward financial rights has proved to be a quagmire still awaiting a set of acceptable rules.

Seams Issues
Regardless of the CMS adopted, the potential incompatibility of that approach with neighboring RTOs will pose issues that will require individual attention. The challenges faced will include at least:
(i) Loop flows across RTOs;
(ii) The definition and allocation of property rights on flowgates between RTOs; and
(iii) Compatibility of energy prices at the seams.

In principle, however, Real Flow has the distinct advantage over an LMP approach of having a partial solution to the seams issue. That is, even if an RTO and all its neighbors adopt an LMP approach, no process has been developed to ensure that the dispatch solutions generated by neighboring pools would be compatible, or that FTRs on RTO interconnections could be allocated and traded in a meaningful manner, or that loop flow issues could be resolved.\(^7\)

With Real Flow, flowgate rights can be defined seamlessly across the Eastern Interconnect, since they are based on NERC’s centralized PTDF calculations. Loop flows across RTOs therefore can be internalized into individual RTO markets by requiring purchases on interacting flowgates across RTOs to purchase appropriate rights in accordance with their flow impacts. Interconnecting flowgate rights could be sold and traded no differently from flowgates internal to the RTOs.

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\(^7\)These issues have been discussed in academic literature, but have not been implemented or proposed in any existing RTO. See Balho H. Kim and Ross Baldick, “Coarse-Grained Distributed Optimal Power Flow,” IEEE Transactions on Power Systems, Vol. 12, No. 2, May 1997, p. 937, Coordinating Congestion Relief Across Multiple Regions, M. Cadwalader, W. Hogan, et al., Oct. 1999.
### III. Comparison of Real Flow and LMP

Table 2: Comparison of Nodal (LMP) and Real Flow
Characteristics and Effectiveness

<table>
<thead>
<tr>
<th>Objectives of CMS</th>
<th>Nodal</th>
<th>Real Flow</th>
</tr>
</thead>
<tbody>
<tr>
<td>Efficiency in Managing Congestion</td>
<td>Sound in theory. However, in practice, dependent on software and input assumptions. (i.e., assumptions and judgement &quot;in the control room&quot;).</td>
<td>Efficient forward market pricing, overall efficiency dependent on combined efficiency of forward and real-time energy markets and selection of flowgates.</td>
</tr>
<tr>
<td>Cost Allocation</td>
<td>May unnecessarily penalize loads for localized transmission problems.</td>
<td>Accurate with appropriate flowgate selection.</td>
</tr>
<tr>
<td>Implementation Costs</td>
<td>Centralization costly. Most suitable for 'tight' pools such as PJM, New York (NY) and New England (NE) or to RTOs with few control areas.</td>
<td>Suitable for loose pools. Provides basis for &quot;seam&quot; management between RTOs. Preservation of control areas simplifies transition.</td>
</tr>
</tbody>
</table>

#### Overall Market Development

<p>| Bilateral Market Activity                      | FTR complexity, product unpredictability/product unmanageability, and time required to calculate prices are barriers to entry and trading of FTRs. Consequently, discourages bilateral energy trading. | Encourages bilateral trading. Market simplicity and well-defined transmission products allow high volume trade and price certainty. |
| Price Certainty                               | Theoretically FTR financial hedges provide certainty. In practice, low liquidity in forward markets and ex-post pricing reduce price certainty. | Liquid, continuous trading on few well-defined products and self-management of congestion in forward markets provides high price certainty. |
| Equity                                        | Can lead to inequitable outcomes at a local level (e.g., factor of 10 difference in prices in same substation in PJM due to different voltage level or price differentials based solely on definition of system components as in Delmarva); consumers pay the price for operator decisions (e.g., deferred investments and arbitrary prices when model won’t solve). | Equitable in the absence of significant congestion on non-tradable transmission elements (which can be mitigated by adding new flowgates). |
| Future Investment                             | Provides correct signals for generation. Little incentive for transmission investment. | Provides correct signals for generation, but with less spatial specificity. TransCo can be designed to have incentive for transmission investment (e.g., take on risk/reward of intra-zonal congestion management). |
| Retail Access                                 | Complexity and ex-post pricing will hinder retail participation. | Effective, because of ex ante, market-based pricing, commercial simplicity and limited pricing areas. |</p>
<table>
<thead>
<tr>
<th>Methodology</th>
<th>Nodal</th>
<th>Real Flow</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Property Rights</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Definition</strong></td>
<td>Financial Rights defined point-to-point. No flow guarantee, but receive payment from RTO against resulting price difference between nodes. Obligation to pay if congestion reverses.</td>
<td>Physical rights defined on &quot;commercially significant&quot; constraints (CSFs) only. No obligation to use - surrendered if unused, no financial exchange with RTO.</td>
</tr>
<tr>
<td><strong>Capacity Release</strong></td>
<td>Periodic auctions, capacity released based on auction bids. Auction requires (Optimal Power Flow) OPF model. Rights can theoretically be traded in secondary markets, though transfers require RTO intervention in NY and PJM, and location-specificity hinders trading. In PJM, quantity-based rationing provides incentives to hoard FTRs.</td>
<td>Periodic auctions on CSFs based on individual flowgate transfer limits. Independently operated exchange allows for continuously cleared bilateral, secondary market for capacity. RTO releases capacity seasonally and as conditions allow.</td>
</tr>
<tr>
<td><strong>Updating System Design</strong></td>
<td>In theory all nodes are defined at the time of system design. In practice in PJM additional facilities are turned over to ISO at the request of transmission owners that results in significant unanticipated and permanent price differentials.</td>
<td>Flowgates for allocation or auction are defined to be those that are “commercially significant.” Definitions are reviewed annually (or more frequently) as a step in the annual reallocation / auction process.</td>
</tr>
<tr>
<td><strong>Handling Loop Flows (within RTO)</strong></td>
<td>Internalized into Optimal Power Flow (OPF).</td>
<td>Handled by requiring transactions to purchase flowgate rights based on contribution of transactions to flows on each flowgate (NERC PTDFs).</td>
</tr>
<tr>
<td><strong>Handling Loop Flows (outside RTO)</strong></td>
<td>Ignores external effects in current implementations. No proven way to synchronize nodal prices or trade congestion rights between RTO’s who have separate optimizations.</td>
<td>Flowgate capacity in adjacent RTOs is required to permit schedules that have significant impact in those RTOs to address external effects of schedules.</td>
</tr>
<tr>
<td><strong>Market Operation</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Forward Markets</strong></td>
<td>- Transmission: secondary market for FTRs - liquidity a major issue, given complexity and non-fungible products. Transfer of FTRs requires RTO involvement. - Energy: Centralized, designated markets (day-ahead, hourly) cleared by RTO using bid-based OPF, no requirement to balance schedules.</td>
<td>- Transmission: Bilateral forward markets available and continuously clearing for commercially significant transmission paths; assures liquid market. - Energy, transmission and ancillary services traded in exchanges (e.g., CA PX) where products are continuously traded and cleared bilaterally up until real-time (hour-ahead). Balanced schedules required to be submitted to dispatcher.</td>
</tr>
</tbody>
</table>

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8 The use of an OPF model is required to clear the auctions because FTRs on all possible combinations of nodes are being sold simultaneously, whose values are inter-dependent.
<table>
<thead>
<tr>
<th>Nodal</th>
<th>Real Flow</th>
</tr>
</thead>
</table>
| **Bilateral Activity (energy)** | Use contracts for differences (CfDs) against pool prices; bid zero or negative into pool to ensure delivery.  
- Price uncertainty and FTR complexity/illiquidity can limit liquidity of bilateral trades for delivery  
- NY and PJM show poor liquidity of contracts for delivery and much difficulty with wheels, imports, and exports. | Dominant transaction form continuously traded in independent exchanges. Market simplicity (price and transmission rights) enables high liquidity. |
| **Real-time Balancing Market/Dispatch** | Centralized RTO performs real-time security-constrained dispatch, producing ex-post energy prices independent of forward markets. In NY, real-time prices revised up to 2 weeks ex post. | RTO runs real-time market only for balancing. RTO performs coordinated dispatch with control areas. Clears real-time congestion based on redispatch process that recognizes existing schedules and uses inc. and dec. bids, as well as ancillary service bids. |
| **Institutional Structure** | **RTO Structure** | Typically not-for profit ISO. For-profit TransCo possible, but serious conflict of interest issues arise due to operation of energy market and the transmission system. | Can be an ISO or a for-profit Transco. |
| **RTO Role in Forward Markets** | **Transmission** | - Controls and manages market for FTRs including capacity release, auction and secondary market.  
- Manages single OASIS site. | - Defines and releases transmission capacity in auctions. Manages single OASIS site. Secondary market for PTRs not run by RTO. |
| **Energy** | Controlling Involvement:  
- Controls and operates energy market for all settlement periods. | Minimal:  
- No involvement in energy market, except for real-time balancing. |
| **Ancillary Services** | Offers all ancillary services, and serves as provider of last resort. Depending on implementation may offer ancillary services market (reserves and frequency control) separate from or combined with energy market. | - Calculates and posts ancillary service (reserves) and loss requirements  
- May purchase ‘call’ contracts in forward markets for reserves and regulation  
- Provider of last resort |
| **RTO Role in Real-time** | RTO performs:  
- Scheduling, system control and dispatch  
- Reactive supply and voltage support  
- Regulation and frequency response  
- Energy imbalance service  
- Spinning reserve  
- Supplemental reserve | RTO performs:  
- Scheduling and coordinated dispatch with control areas  
- Energy imbalance service  
Control areas perform all other ancillary services under the coordination of the RTO, and based on resources procured by the RTO. |
Cost Comparison
As discussed earlier, the implementation and operating costs associated with Real Flow are likely to be significantly less than with an LMP approach. Table 3 below shows the general cost categories and relative cost expectations of the two approaches.

Table 3: Comparison of Real Flow and LMP Implementation Costs

<table>
<thead>
<tr>
<th>Implementation Costs</th>
<th>Nodal</th>
<th>Real Flow</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital (Outlay) Costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Software systems development*</td>
<td>Higher</td>
<td>Lower</td>
</tr>
<tr>
<td>Administrative structure (staff, facilities, equipment, etc.)</td>
<td>Higher</td>
<td>Lower</td>
</tr>
<tr>
<td>Market exchanges</td>
<td>Lower</td>
<td>Higher (borne by exchange developers)</td>
</tr>
<tr>
<td>Training and consulting</td>
<td>Higher</td>
<td>Lower</td>
</tr>
<tr>
<td>Operations Cost</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Compensation, benefits, consulting services,</td>
<td>Higher</td>
<td>Lower</td>
</tr>
<tr>
<td>Facility costs (leases)</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Misc. expenses</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Indirect Costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Market participant training*</td>
<td>Higher</td>
<td>Lower</td>
</tr>
<tr>
<td>Unquantifiable costs of market inefficiency*</td>
<td>Higher</td>
<td>Lower</td>
</tr>
</tbody>
</table>

*Areas where significant cost differences are expected between nodal and Real Flow