UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Entergy Services, Inc.,	)	
on behalf of the Entergy Operating Companies: Entergy Arkansas, Inc., Entergy Gulf States, Inc., Entergy Louisiana, Inc., Entergy Mississippi, Inc., and Entergy New Orleans, Inc.	)	Docket No. RT01-_____

TESTIMONY

OF

MICHAEL M. SCHNITZER

ON BEHALF OF

ENTERGY SERVICES, INC.

October 16, 2000

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Michael M. Schnitzer. I am a Director of the NorthBridge Group, 55 Old Bedford Road, Lincoln, Massachusetts 01773. The NorthBridge Group is an economic and strategic consulting firm specializing in the electric and natural gas industries.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Entergy Services Inc. ("Entergy," "ESI," or "the Company").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKROUND.

A. I received a Master of Science degree in management from the Sloan School of Management, Massachusetts Institute of Technology, in 1979. My concentration was in finance. I received a Bachelor of Arts degree in chemistry, with honors, from Harvard College in 1975.

In 1992, I co-founded The NorthBridge Group. Before that, I was a Managing Director of Putnam, Hayes & Bartlett, which I joined in 1979. At NorthBridge and at Putnam, Hayes & Bartlett, I have consulted for private sector clients in the electricity, natural gas, and steel industries, and for several public and

nonprofit agencies. My electricity work has recently focussed on industry restructuring issues. Further details of my professional and educational background are set forth in MMS-1.

Q. PLEASE LIST THE REGULATORY COMMISSIONS BEFORE WHICH YOU HAVE TESTIFIED.

A. I have provided testimony or affidavits on a variety of matters before this Commission and regulatory commissions in Arkansas, Delaware. Indiana, Maine, Maryland, Massachusetts, New Hampshire, New Mexico, New York, Ohio, Pennsylvania, Rhode Island, Texas, Vermont and Wisconsin.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Order No. 2000 sets out the minimum characteristics and functions that must be met in order to gain RTO status. Establishment of a Transco and participation by the Transco in an SPP Partnership RTO is the mechanism by which Entergy proposes to promote a competitive regional wholesale power market and meet the Order No. 2000 requirements. While the details of the Partnership RTO are described by other Company witnesses, my testimony addresses the major market design aspects of the Company's RTO proposal: – real time and forward energy markets, congestion management, transmission rights and pricing, and the like. To do this, I first describe why FERC's Order No. 2000 requirements for market

design, congestion management and transmission pricing cannot be met through the status quo market system. In the second section of my testimony, I next describe Entergy's preferred approach to market design – a real time balancing market using locational marginal pricing (LMP) principles, congestion pricing for transmission schedules, financial transmission rights (FTRs) to hedge congestion risk, a reserve requirement for load serving entities, and a set of proposals and incentives for both market-funded and rate-funded transmission expansion. In this section of my testimony, I also discuss why Entergy prefers this approach, as well as the criticisms raised by some other market participants concerning LMP and in particular FTRs. In the third section of my testimony, I describe the so-called "hybrid" market design that is under development within SPP which would include flow-based flowgate rights (FGRs) as a supplement to or substitute for the point-to-point FTRs in Entergy's preferred market design. I also discuss the principal remaining open issues in the proposed hybrid design, and the tradeoffs that arise in a flowgate model.

II. STATUS QUO MARKET SYSTEM

Q. PLEASE DESCRIBE THE CURRENT SYSTEM.

A. The current system is largely premised on vertical integration and centralized integrated planning. That is, the core of the current system is a number of vertically integrated control area operators who own generation and plan for and

serve their native load on a priority basis, rather than a decentralized structure operating on the basis of price signals to generators and other market participants. In a system premised on vertical integration, price signals are not required for planning purposes. When planning new generation, an integrated company considers generation and transmission economics (including transmission congestion) simultaneously, and the transmission implications of a particular generation investment are included in the economic assessment. In real time, vertically integrated control area operators manage congestion within their areas through out-of-merit dispatch (redispatch) of their own generation.

In a vertically integrated industry structure, this design can be effective. But when generation is made competitive at the wholesale level, and the transmission system operator must be independent rather than integrated, the design breaks down. Indeed, some problems are already apparent.

Q. WILL THE CURRENT SYSTEM MEET THE COMMISSION'S ORDER NO. 2000 REQUIREMENTS FOR MARKET DESIGN, CONGESTION MANAGEMENT AND TRANSMISSION PRICING?

A. No, it will not. Two types of problems are already apparent, and I expect the current system to become increasingly unworkable in the future.

The first problem that is already evident relates to the development of new generation. Company witness George Bartlett explains in his testimony that a significant amount of "merchant" generation is already under development or has

been proposed in Entergy's region. As the Commission has recognized, depending on where generation is sited, its operation can create transmission congestion that affects other users, and require upgrades to the transmission system. This electrical impact – that is, the consequences of the location of new generation on congestion and upgrade costs -- should be one of a number of economic considerations in choosing the location of new generation, along with site availability and cost, proximity to fuel sources, and state and local siting and permitting considerations. Yet, under the current system, the developers of this generation do not "see" the congestion implications of their (and their competitors') location decisions, nor are there good price signals to guide them. In the absence of efficient price signals (which are required in RTOs under Order No. 2000), there can be no confidence that economically efficient decisions are being made with respect to electrical location of new generation.

The second problem is regional congestion management. Under the current system, for the most part congestion is managed through blunt instruments -- denying transmission service requests and ultimately through TLR (Transmission Loading Relief). As the Commission noted in the RTO NOPR and reiterated in Order No. 2000, the TLR process does not attempt to optimize regional congestion relief and is cumbersome, inefficient and disruptive to bulk power markets. (p 334 of Order No. 2000). And efforts at reducing the incidence of TLRs through counter-flows arranged bilaterally (NERC's so-called "market redispatch" process) have thus far been unsuccessful. Thus, at present we have

neither a price structure that "promotes efficient regional dispatch" so that "generators that are dispatched in the presence of transmission constraints are those that can serve system loads at least cost" (Order No. 2000, pp. 332-333), nor a congestion management system that "sends efficient price signals regarding the consequences of transmission use decisions" (p.382) so that limited transmission capacity is used by those who "value its use most highly" (p.332) – both of which are required of RTOs under Order No. 2000. In short, the current regional congestion management system falls short of Order No. 2000 standards today, and I expect it to become more unworkable in the future.

Q. PLEASE EXPLAIN WHY THE CURRENT SYSTEM WILL BECOME INCREASINGLY UNWORKABLE.

A. The current system is workable today only because the core of a vertically integrated system still exists. However, vertical integration in the Entergy region is being eliminated from three different directions.

First, to comply with Order No. 2000's requirements, Entergy will structurally separate transmission from generation through the establishment of the Transco. Unlike a vertically integrated utility, Transco will not be able to simply direct generators to run out of merit or to redispatch to optimize flows within its region. Nonetheless, as a system operator and control area operator the Transco must be able to ensure that generation is dispatched to serve all load while respecting binding transmission limits. The most efficient way to accomplish this

is through a market-based system that gives generators accurate, visible price signals.

Second, during the next several years retail access will be implemented in two states in which Entergy operates. The volume of wholesale schedules will increase substantially over the current level, as load that was formerly part of bundled native load becomes eligible for retail access and is served by load aggregators. This is another reason why Entergy will no longer be able to rely on redispatch by a vertically integrated entity to manage congestion in its control area.

Third, there will be a substantial increase in the amount of new merchant generators in the region who will seek to serve load in the region or export from it. These generators will not be part of a vertically integrated system. Operation of the grid under the current model will become increasingly awkward and inefficient under these circumstances. With diminishing levels of vertical integration and increasing levels of competitive wholesale transactions, today's system must be replaced by a market-based model that allows access to the grid based on price as specified in Order No. 2000. In the next section, I describe Entergy's preferred market design, which it proposed to SPP.

III. ENTERGY'S PREFERRED MODEL

Q. PLEASE GIVE A BRIEF OVERVIEW OF ENTERGY'S PREFERRED MARKET MODEL.

A. Entergy's preferred market model has three major components:

- A real-time balancing market based on LMP principles with financial transmission rights (FTRs) to hedge congestion (I refer to this as the LMP/FTR model or simply the LMP model);
- A generation reserve requirement applicable to all load serving entities, to maintain reliability in a restructured environment; and
- Provision for both market-funded and rate-funded transmission expansion, with associated incentives for Transco to build new facilities when they are economic.

A. LMP/FTRs

Q. PLEASE DESCRIBE THE LMP/FTR MODEL.

A. In an LMP model, the system operator runs a real-time market for balancing energy.[1] It receives schedules from parties arranging transactions between themselves ("bilateral" schedules) and it receives voluntary bids from suppliers, including incremental ("inc") and decremental ("dec") bids from generators on bilateral schedules. Using the schedules and bids submitted, and its real-time information about the transmission network, it ensures that generation is dispatched so that (a) load is served reliably at least cost (based on bid cost to the system operator) and (b) the economic use of the grid is maximized. This fulfills

[1] There may also be a day-ahead or hour-ahead LMP market.

the Order No. 2000 requirement for a price structure that promotes efficient regional dispatch.

The locational marginal price at any given location is the value to the system operator of additional energy at that location.[2] If the location is a generator bus, that generator's bid may or may not set the LMP there, depending on whether that unit is fully dispatched. If a generator runs, it will be paid at least its bid price. If it is fully dispatched, the LMP at its location will be set by another generator and will exceed its bid price. If a unit's bid is not accepted, it is because energy to serve loads can be provided less expensively from other resources.

In an LMP model, generators are paid the LMP at their bus for energy that they supply through bids to the system operator. For load purchasing balancing energy in the LMP market, the price may be the LMP at its location, or it may be an LMP averaged over a number of locations. But it is important to understand that the LMP charged to load is a marginal price – it is what it will cost to buy energy to serve the next increment of load at that location or locations, not what it costs on average to supply all of the load's purchases.

Parties scheduling bilateral transactions determine their energy price through commercial negotiations.[3] They pay for transmission usage in the form of

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[2] Technically, the LMP is what it would cost the system to serve an increment of load at a given node (generator bus or load substation), even if no load is actually located there. The LMP includes the bid cost of the generator that would be called upon to serve the next increment of load at that node. (This unit is called the marginal generator.) The LMP also includes the cost of the incremental congestion that would occur as a result of serving the incremental load from the marginal generator, taking into the account the impacts on all elements of the transmission network.

[3] Parties self-scheduling owned generation are technically submitting bilateral schedules.

a schedule-specific congestion charge, based on the difference in LMPs between their point of injection (POI) and point of withdrawal (POW). Thus, all participants withdrawing energy from the grid pay for congestion – either implicitly through the LMP or explicitly through the congestion charge. They are charged for the "consequence of their transmission use decisions", as required by Order No. 2000.

Q. CAN PARTIES HEDGE CONGESTION CHARGES?

A. Yes, parties can hedge congestion charges through financial transmission rights (FTRs). FTRs are point-to-point financial instruments; a party holding an FTR is paid the difference in LMPs between the designated point of injection and point of withdrawal on the FTR, for the quantity and term of the instrument. This is true whether the party schedules a bilateral transaction, whether it buys or sells energy in the LMP market, or whether it does none of the above.

By holding an FTR that "matches" a bilateral schedule, a party can hedge congestion charges and be assured of delivered price certainty for its transaction. In effect, a party buying such an FTR has prepaid congestion for its transaction. But a party does not need an FTR in order to schedule a transaction. And, as noted, an FTR holder is paid regardless of whether it schedules a matching transaction, or any transaction for that matter. These last two points are very important; they distinguish financial rights from so-called "physical rights" (about which I say more later.)

Q. HOW WILL PARTIES OBTAIN FTRs?

A. Through an initial allocation process (which I discuss later), through an auction of remaining FTRs, and/or through secondary market transactions.

Q. HOW WILL FTR HOLDERS BE PAID?

A. The system operator will use revenues that it receives from congestion charges to pay FTR holders. There are two sources of congestion revenues: congestion charges assessed to bilateral schedules, and excess congestion received through the operation of the LMP market.[4] The "actual" schedules and dispatch do not have to match the FTRs in order for the system operator to have enough revenues to pay the FTR holders in full. So long as the system operator has not sold more FTRs than can be supported by the transfer capability of the grid, and so long as the transfer capability remains intact, the system operator will have sufficient congestion revenues to be able to fund FTRs regardless of the actual flows.

Q. WHY DOES ENTERGY ADVOCATE AN LMP MODEL FOR ITS REGION?

[4] Excess congestion revenues can occur when the system operator serves load in a transmission-constrained area partly from generation located outside the constraint. If the LMP is lower outside the constraint, it will serve the load from the distant generation, up to the limit of the system, and then serve the remainder from more expensive local generation. It will charge the load for all its LMP purchases based on the marginal cost to serve it – the LMP of the local generation. But since the LMP outside the constraint was lower, it will pay those generators less than it charges the load. Thus in this circumstance it will collect more in total from load in the LMP market than it pays to generators. This excess revenue will be used to fund payments to parties holding FTRs, including FTRs into the constrained area.

A. There are several reasons why Entergy believes LMP is the preferred model:

1. LMP allows the system operator to identify and implement all economic redispatch opportunities and maximize the use of the grid across the region in the face of transmission constraints, while providing the most efficient dispatch to serve load. For Entergy, which is already faced with a congested system, retail access and new merchant plants, it is critical to put in place a market design that will yield the most efficient use of the grid and serve load at least cost. (By cost, I refer to the cost to the system operator, based on bids received, not a generator's cost of service.)

2. LMP recognizes all operational constraints on the transmission system, and the associated congestion costs, and assigns these costs to the transactions causing them (the "cost-causative" parties.) It thus minimizes the "socialization" of congestion management costs. (By socialization, I mean a situation in which the system operator charges redispatch cost to all load through so-called "uplift" charges.)

3. LMP sends clear, visible price signals for new generator location and clarifies the standards for new generator integration.

Q. WHY DOES ENTERGY FAVOR FINANCIAL TRANSMISSION RIGHTS (FTRs)?

A. Again, there are several reasons:

1. FTRs can be used to hedge congestion charges for particular physical transactions (energy injections and withdrawals) or can be used to support trading positions.

2. FTRs provide a structure for a meaningful transmission performance incentive. The system operator's ability to fully fund payments to FTR holders is largely a function of grid availability, so the level of revenue inadequacy/surplus to pay FTR holders is a direct measure of the economic consequences of grid availability. It is possible to fashion an incentive for the Transco that gives it a stake in FTR under/over funding, and thus an incentive for maintaining economic grid availability.

3. The price of FTRs gives signals about the expected cost of congestion, and thus the value of transmission expansion or debottlenecking. FTRs thus enable market-funding of transmission expansion, as I discuss below.

4. FTRs provide a mechanism for an equitable conversion plan for existing firm customers, including bundled retail customers.

Q. WHAT DO YOU MEAN BY AN EQUITABLE CONVERSION PLAN FOR EXISTING FIRM CUSTOMERS?

A. As restructuring of the industry has proceeded, many transition issues have emerged. One important issue is how to provide a fair and balanced method to convert native load and other firm customers from the current system to a new one.

In the context a new market structure that includes transmission rights (such as FTRs in the case of an LMP model), the conversion question arises with respect to the initial distribution of rights, or distribution of auction revenues if the rights are to be auctioned. Technically, there are a number of possible transition models that could be used. For instance, the initial distribution rule could be "all rights belong to the transmission provider, who can auction them, use the revenues to upgrade the system, and increase throughput and reduce congestion." Or the rule could be "all rights (or auction revenues) are distributed to existing firm customers on a load-ratio share basis." A third choice would be "rights are distributed to existing firm customers in accordance with their current firm use of the transmission system." By existing firm customers, I am referring to bundled native load customers (or the utility serving them), long-term firm point-to-point customers, network service customers, and customers operating under firm contracts or service arrangements that pre-date Order 888 and the pro forma tariff.

Q. WHICH METHOD DOES ENTERGY FAVOR?

A. In choosing among these alternatives, Entergy believes that the third method, in which transmission rights are initially distributed to firm users in some equitable fashion that takes into account existing usage, is the preferable method. Once the rights are distributed, the holders will be free to sell them or hold them. In the future, if they desire additional rights to hedge congestion because, for instance, their load has grown, they can buy the additional rights from existing holders, or,

they can fund transmission expansions and receive new rights associated with the new system capacity that they created via their investments. (System expansion is discussed more fully below.) This method is preferred because it will minimize cost shifting within the group of existing firm users. It will also ensure that future grid improvements are, to the maximum extent possible, paid for by those who will benefit from them rather than by all transmission customers as a group.

To promote liquidity of the FTR market under this method, Entergy favors several further steps. First, after the initial distribution of FTRs, any additional available rights will be auctioned. Second, to ensure liquidity under retail access, Entergy supports a requirement that when customers become eligible for retail access, FTRs received in the initial distribution to serve them must be released by the utility on a pro rata basis.

Q. HOW DO FTRs FACILITATE SUCH A CONVERSION PLAN?

A. The point-to-point nature of FTRs facilitates this plan. Because FTRs are point-to-point, firm users can be allocated a set of FTRs that match their current firm use of the system. That is, they can receive a set of rights that assures them access to the generation resources that they have historically depended on, without any exposure to congestion. They will have a hedge matching their current transmission arrangements so long as their supply pattern remains unchanged. In the future, if their supply pattern changes, they can trade or reconfigure these FTRs. But they need not do so, as FTRs serve as a partial hedge even if they do

not precisely "match" a transaction in terms of point of injection or point of withdrawal. I will return to the subject of FTRs and conversion rights below, when I discuss an alternative form of rights, flowgate rights, that I believe do not provide as sound a basis for a conversion plan.

Q. IS PROVIDING CONVERSION RIGHTS TO EXISTING CUSTOMERS CONSISTENT WITH THE OBJECTIVE OF PROVIDING ACCESS TO THE GRID BASED ON WILLINGNESS TO PAY?

A. Yes. A system of managing grid use based on willingness to pay is consistent with an equitable conversion plan. If the new system is based on FTRs, as the Company has advocated, then the initial allocation of rights (or auction revenues) does not affect the operation of the system, including scheduling and redispatch. That will be based on schedules and bids submitted to the system operator, not based on who holds what right. Any party willing to pay congestion can have a schedule accepted, and any party wanting to hedge or pre-pay congestion can seek to buy an FTR at auction or in the secondary market. Furthermore, the FTRs initially allocated to firm users can subsequently be sold, so that if a new user values those FTRs more highly than the firm user to whom the FTRs were initially allocated, the new user can buy them.

Q. GIVEN THE BENEFITS THAT ENTERGY SEES IN AN LMP/FTR MARKET DESIGN, WHAT OBJECTIONS HAVE BEEN RAISED TO THIS MODEL?

A. There are several objections that have been raised in one forum or another. For example, it is often alleged that LMP is too complex and costly; it is too centralized and bureaucratic; it is not necessary in regions with little congestion; and/or it is not necessary in regions with a homogeneous fleet of generation. Some have also complained that it does not provide price certainty and does not support a liquid forward market. In conducting its own assessment, Entergy has concluded that either these objections are without merit, or that the potential problems are far outweighed by the benefits discussed above.

Q. PLEASE EXPLAIN.

A. As to the first point, that LMP is too complex and costly, the question must be asked – compared to what? The fact is that the electric grid is highly complex because of its network characteristics. Entergy reviewed all the available market design options and concluded that there is no other model that deals with this complexity as effectively. There may be models that are less expensive to implement, including the option of staying with the status quo, but they will yield higher costs for consumers overall.

As to whether LMP is too centralized and bureaucratic, the nature of the grid is such that a central system operator is required to maintain reliability. Given the complexity and short-lived nature of network effects, in real time only the system operator is in a position both to maintain reliability and to maximize the economic use of the grid. LMP simply gives the operator the tools it needs to do

that. These include access to voluntary bids from all parties, and a pricing model that gives every party a financial incentive to offer a redispatch option to the system operator. The system operator does not take a position in the market, nor can it order parties to bid. The bids are voluntary and market-based (assuming the supplier has market-based rate authority.) Thus, LMP does not represent a mandatory pooled dispatch as that concept is traditionally viewed.

The argument that "we don't need LMP because we don't have congestion in our area" is not heard in the Entergy region, because the congestion here is already obvious. But it is worth noting as a general observation that absence of significant TLRs does not mean that there is no congestion in a region. As I discussed earlier, vertically integrated utilities manage congestion "invisibly" through out-of-merit order dispatch at the retail level and denials of request for service at the wholesale level.

As to the argument that LMP is not needed if the generation fleet in a region is homogeneous – i.e. all units have the same or similar dispatch cost – this overlooks the differential transmission congestion effect that a generator can have, depending on where it is located electrically. Thus, in many circumstances, the system operator needs a way to differentiate among generators with similar costs, but different effects on a constrained network element. Without LMP pricing, there is no way to send a price signal that results in the right generator running more, and other generators running less, or not at all.

Q. WHAT ABOUT THE CLAIMS THAT THERE IS NO TRANSMISSION PRICE CERTAINTY UNDER THE LMP MODEL AND THAT LMP DOES NOT SUPPORT A LIQUID FORWARD MARKET?

A. In my opinion these claims are unfounded. Since they are often made by advocates of a physical rights model, perhaps it would be useful if I first described the differences between physical and financial transmission rights. Then I will discuss the price certainty and liquidity claims.

Q. WHAT IS THE DIFFERENCE BETWEEN PHYSICAL AND FINANCIAL RIGHTS?

A. There is no textbook definition of a "physical rights" model, but it generally refers to a structure in which market participants must hold a right in order to schedule a transaction, and thus much of the scheduling and dispatch of generators is determined through private trading of such rights. Entergy does not believe that such a model would be workable for the electric grid in its region and could not support a model with such a requirement. In contrast, in a financial rights model no right is required in order to schedule a transaction.[5]

Another feature of a physical rights model is that the rights are "use it or lose it". In other words, if the rights holder elects not to schedule a transaction using the right, and does not trade it away, it is not entitled to any payment from the transmission provider, who may use the capacity to sell non-firm transmission,

[5] As I explain below, in the hybrid model currently under development at SPP there will be no requirement that parties hold rights in order to schedule.

for instance. As I explained earlier, financial rights (FTRs) do not have this characteristic; regardless of whether holders schedule transactions matching their FTRs, they are entitled to a financial settlement for the value of the right. The use it or lose it rule is said to discourage hoarding of rights and encourage market liquidity. Of course, hoarding is only a problem if it is necessary to acquire rights in order to schedule a transaction; since this is not a requirement of FTR-based systems, there is no need to combat hoarding in such systems. Meanwhile, a physical right that is subject to a use-it-or-lose-it rule offers less flexibility than an FTR. If a physical rights holder changes its supply arrangements, it must find a buyer for its right in order to realize value for it. This is not true for FTR holders.[6]

Q. WHAT ABOUT THE QUESTION OF "OPTION" VERSUS "OBLIGATION"?

A. Physical rights are generally defined as "options". A party holding a physical right defined as an option may use it to schedule a transaction, or it may let the right lapse (in which case the capacity associated with the right may become available as non-firm transmission, depending on the timeframe involved and the specific market rules.) In contrast, to date, LMP models have defined FTRs as obligations. FTR holders receive congestion payments when the difference between the LMP at the point of withdrawal for the FTR and the point of injection is positive, and they have an obligation to make payments if the price relationships reverse and

[6] See Figure 1 for an illustration of the partial hedge characteristics of FTRs.

congestion is "negative".[7]

Some market participants favor defining rights as options, because they want the flexibility to avoid charges for negative congestion. There is nothing inherent about FTRs that prevents them from being defined as options. The decision to define them as obligations in other regions has been driven by one consideration: if the rights are defined as obligations rather than as options, more rights can be issued. Why? If the rights are obligations, the issuer knows that the equivalent of counterflow will be in place. If the rights are options, no such assumption can be made. Without counterflow, fewer rights can be issued.[8] Indeed, in some existing LMP/FTR systems ISOs have sought and found market participants willing to be paid to take FTR obligations that are expected to be negative, i.e., they have paid parties to take on the obligation to fund critical counterflows.

The possibility that the RTO will offer FTRs defined as options will be considered seriously in market design, although if FTRs are defined as options in order to address the concerns of some marketers, and there are far fewer of them

[7] Negative congestion does not affect delivered price certainty for FTR holders scheduling actual transactions. If congestion is negative between the POI and POW of the FTR, it means that the parties scheduling that transaction will be paid, not charged, congestion for that transaction, because they are actually relieving congestion by scheduling a counterflow transaction. See Figure 2 for an example.

[8] Fewer rights can be issued in the context of a "simultaneous feasibility" test. In an FTR model, FTRs are supposed to be "simultaneously feasible." This means that, for a given set of FTRs in circulation, assuming the transmission system is intact, the transmission provider (or whatever entity issued the rights) will have sufficient revenues to pay the FTR holders what they are entitled to.

available, that will work against market liquidity.[9] Defining FTRs as options also hinders the implementation of an equitable conversion plan for existing firm customers. It is important to recognize these undesirable side effects of structuring rights as options instead of obligations.

Q. HOW DO YOU RESPOND TO THE CLAIM THAT THERE IS NO TRANSMISSION PRICE CERTAINTY WITH LMP?

A. It is not correct. Under either a financial rights or a physical rights model, transmission price certainty is achieved the same way – through purchase of a transmission right. Participants in the forward markets will either have obtained a hedge through the purchase of a physical or financial right or they will not. In both cases, if the parties have a right they will have no transmission price uncertainty; if they failed to purchase a hedge, they will not have price certainty.

When the response is made that price certainty in an LMP model is achieved by buying an FTR, sometimes the "no price certainty" claim is then restated as a liquidity issue: price certainty can only be achieved through purchase of an FTR, but FTRs are alleged to be inherently illiquid, and thus price certainty is unattainable as a practical matter. I disagree, as I explain in my next answer.

Q. WHAT ABOUT THE ARGUMENT THAT FTRs DO NOT SUPPORT A

[9] The same result will hold in a physical rights world – fewer rights can be issued if they are defined as options, assuming that a simultaneous feasibility test must be met. However, some physical rights advocates would relax that test and have more rights issued than might be

LIQUID FORWARD MARKET?

A. Some market participants argue that because FTRs are point-to-point, they are custom instruments, not liquid commodities. They claim that an FTR is good as a hedge only for one specific transaction, and that it will be difficult to acquire an FTR to hedge a different transaction. They point to experience in other LMP markets where they allege there has been little trading of FTRs, and claim that they are intrinsically illiquid. As an alternative, some market participants would prefer a zonal pricing model, with uniform prices by zone and transmission rights defined on a zone-to-zone basis. Such rights, it is claimed, would be intrinsically more liquid.

In response, I would first note that the rules for initial allocation of rights may affect the liquidity of the secondary market in transmission rights, be they FTRs or some other kind of right. Experience in other markets may be a function of a flawed allocation scheme that did not get rights into the market, not some intrinsic problem with LMP and FTRs. Entergy's initial rights allocation proposal, which I described earlier, should minimize these problems. Second, experience to date with market liquidity in an LMP/FTR environment in PJM has been positive; one of the most liquid forward markets in the country has developed at its Western Hub.

As to the view that a zonal pricing model is the way to promote liquid transmission rights, I would carefully distinguish between a zonal pricing model

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simultaneously feasible, and leave it to the transmission provider to buy back rights that became infeasible. Entergy would oppose this approach.

and zone-to-zone transmission rights. I agree that zone-to-zone transmission rights may be more fungible and thus support a more liquid market in transmission rights than point-to-point rights. However, that is not a reason to adopt a zonal pricing model. Entergy evaluated the zonal pricing model closely and concluded (a) zonal pricing of energy introduces many problems, as experience with California's zonal model has shown, and (b) it is possible to offer zone-to-zone FTRs within an LMP context.

Q. WHAT ARE THE PROBLEMS INTRODUCED UNDER A ZONAL PRICING MODEL?

A. In a zonal pricing model for generation, a set of zones is defined. Within each zone, units will initially be scheduled based on an unconstrained merit order dispatch. The unconstrained dispatch sets the single clearing price for the zone. If, however, it is not feasible to run a unit as scheduled because intrazonal constraints do in fact exist, then that unit will have its scheduled output reduced, and another unit on the other side of the intrazonal constraint will have its output increased above its merit order dispatch level.

This raises the question of what each of these two units whose output was modified will be paid. Clearly the unit that was "constrained on" will insist on receiving its bid, which by definition is above the unconstrained clearing price set by a merit order dispatch. Similarly, the unit that was "constrained off" will seek compensation for the output that appeared "economic" (in merit order) but which

was not taken. This unit would expect to receive the difference between its bid price and the unconstrained zonal price for all scheduled but undeliverable MW.

These "constrained-off" payments create an opportunity for gaming. A unit knowing that it will be constrained off due to intrazonal constraints may bid below its actual operating cost so as to maximize its constrained-off payments. The costs associated with this gaming will be socialized -- passed on to all customers in the zone through an uplift charge.[10,11] In contrast, with a nodal pricing system for generators, the constrained unit will be paid its nodal price, which could be set by its own bid. Thus it will have no incentive to game the market by underbidding. And there will be no constrained-on or –off payments to generators to be socialized.

Splitting the market into additional zones would reduce the gaming and socialization problem. But if it is attempted after the start of market operations. it will likely evoke resistance, especially from incumbents whose zonal clearing price would be lower under the new zonal configuration. Holders of long-term contracts that were written against the initial zonal configuration may also protest.

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[10] This form of gaming has most noticeably been observed in the U.K. market where the extent of the abuse caused the regulator to step in on more than one occasion

[11] An extreme version of this problem can arise if a generator creates interzonal congestion (meaning it decreases transfer capability between two zones when it runs, a not unheard-of situation.) If it has an incentive to create inter-zonal congestion (for instance, because it is affiliated with a generator in another zone) it may bid low to assure it is accepted in merit order. It will be paid the clearing price in its zone, not its bid, and drive up the price in another zone. Under LMP pricing, the financial incentives would be different. The LMP at its bus would be very low, reflecting the congestion it creates throughout the system when it runs. If it created enough congestion the LMP at its bus could even be negative, accurately reflecting the value to the system of injection of energy at that location.

The weakness of zonal pricing for generators is highlighted when the issue of new generation siting is considered. The problems that California has had with new generation siting can be traced in large part to the shortcomings of the zonal pricing model it is using. Under zonal pricing, generation developers will not have an incentive to locate in transmission-constrained locations within a zone, based on the zonal pricing signals available to them. In fact, a developer could have a perverse incentive to locate in a "constrained-off" area, so as to be entitled to payments not to generate. Any decision to site in a "constrained-off" area could exacerbate intrazonal constraints.

In contrast, with LMP pricing for generation, a developer would have a visible price signal giving an incentive to locate in a 'constrained-on" area in the zone, because it would have higher-price nodes under LMP. These siting decisions would contribute to relieving intrazonal constraints

Q. CAN WE HAVE ZONE-TO-ZONE FTRs IN AN LMP CONTEXT?

A. Yes, we can. Clearly, in my view LMP pricing for generators is far superior to a zonal pricing model for generators.. Fortunately, there is a way to offer zone-to-zone rights within an LMP environment. Basically, this is done by defining a set of transmission trading hubs within the region. The hubs can be LMP nodes or groups of LMP nodes. Once these hubs are designated, any point-to-point FTR can be "decomposed" into 3 component FTRs: an FTR from the point of injection (POI) to a hub; an FTR from one hub to another hub, and an FTR from that hub to

the point of withdrawal (POW). This concept is illustrated in Figure 3. The hub-to-hub FTRs can be freely traded to support forward market transactions. The "stub" FTRs (POI to hub or hub to POW) will not be as liquid, and will likely remain in the hands of generators or load-serving entities.

Under this approach, LMP will still be the pricing protocol for transmission congestion. In other words, the system operator will charge transactions for congestion on a POI to POW basis. There will be no socialization of what would be considered "intrazonal" congestion under a zonal pricing model. Entergy believes that this method for developing zone-to-zone FTRs is superior to an approach that relies on a zonal pricing model in which intrazonal congestion is socialized.

B. RESERVE REQUIREMENT

Q. WILL THE LMP/FTR MODEL THAT ENTERGY ADVOCATES ADDRESS SUPPLY ADEQUACY IN THE REGION?

A. This is currently a matter of some debate in this country. Some believe that well-functioning energy markets will give adequate price signals to bring forward sufficient new supply. Others point to the inelasticity of electricity demand and the lead time to build new capacity and conclude that, until there are sufficient quantities of price-responsive load that can participate in and clear the wholesale

market, some physical reserve requirement (also referred to as an installed capacity requirement) is appropriate.

Q. DOES ENTERGY SUPPORT CONTINUATION OF A PLANNING RESERVE REQUIREMENT IN A RESTRUCTURED INDUSTRY?

A. Yes. Currently, Entergy maintains planning reserves of approximately 15%. The issue for the future market design is whether under retail access we will preserve the concept of a reserve requirement, and, if so, how it will be implemented through load aggregators. Entergy believes that there should be such a requirement, at least for a transition period, and believes that one will be adopted by SPP. However, the topic is currently under study at SPP. It should be noted that there are many ways to design and implement such a requirement. Entergy expects that this will be addressed in the revised SPP RTO tariff to be filed next year.

C. TRANSMISSION EXPANSION

Q. PLEASE EXPLAIN THE IMPORTANCE OF PROVIDING FOR ECONOMIC EXPANSION OF THE TRANSMISSION GRID.

A. The existing transmission system in Entergy's area was designed on an integrated basis to serve native load customers from utility-owned generation. With the advent of merchant generation and retail access, new patterns of transmission

usage will likely result. Network customers (including current native load, whether it remains "bundled" or moves to open access) may seek to change suppliers, and merchant generators may seek export opportunities. Entergy fully expects that grid upgrades will be required to support these wholesale and retail market activities. It is therefore important that the market design facilitate the identification and funding of these expansion projects when they are economic.

Q. HOW DOES THE LMP/FTR MODEL SUPPORT ECONOMIC EXPANSION OF THE TRANSMISSION SYSTEM?

A. In two ways. First, visible locational prices provide an economic signal as to the magnitude and frequency of transmission congestion that could be eliminated or reduced through expansion of the grid. In short, locational prices indicate where the problems are, and how much it might be worth to fix them. Second, this model creates a property right – FTRs – that enables a new way to fund transmission expansion, market funding, in addition to the more familiar rate funding option.

Q. PLEASE EXPLAIN MARKET FUNDING OF EXPANSION.

A. A market structure such as LMP creates tradable property rights in transmission. The number of FTRs that can be in existence at any one time is limited by the transfer capability of the grid, because the issuer will not offer more FTRs than can be supported by a simultaneous feasibility test. Transmission expansions that increase transfer capability, however, will permit additional FTRs to be created.

The nature of these rights creates an opportunity for market funded expansion

The basic concept behind market-funded expansion is that parties who fund grid expansions receive all the long-term FTRs created by the expansion. The transmission provider determines the mix and quantity of incremental FTRs that are created by the investment. These incremental rights are supposed to capture all the network effects of the expansion. This model addresses the free rider problem that has heretofore hindered market funding: if an upgrade funded by one party relieves someone else's congestion, under the pro forma tariff there is no way to give the investing party a set of transmission rights that reflect the full value created by its investment. FTRs provide such a vehicle.

Q. WOULD ANYONE REQUESTING NEW FIRM SERVICE BE SUBJECT TO A REQUIREMENT TO FUND TRANSMISSION UPGRADES?

A. No. Anyone paying an access charge (i.e. a license plate rate) can schedule a transaction, but they will be subject to congestion if their schedule is not "covered" by transmission rights. Whether we are in "pure" LMP or a hybrid, a party needs to obtain a right in order to be hedged against congestion. Rights can be obtained in an initial allocation, or bought at auction or in a secondary market. If no right is available at a price the customer is willing to pay, it can seek to obtain the right from the transmission provider by funding an upgrade. This form of transmission pricing was approved for the NYISO.

Q. IS MARKET FUNDING DIFFERENT THAN THE "HIGHER OF" PRICING OF UPGRADE COSTS UNDER THE CURRENT PRO FORMA TARIFF?

A. Yes, it is different than "higher of" pricing. The transmission customer would continue to pay any congestion costs associated with its transaction, together with any applicable network or point to point charges. In addition, the customer would pay for the upgrade based on costs (or in some cases, at an auction-determined price), and would receive the FTRs associated with the upgrade in return.

Q. DOES MARKET FUNDING OF TRANSMISSION EXPANSION INVOLVE MARKET-BASED RATES FOR TRANSMISSION SERVICE?

A. No. Transco recovers its cost, although this may include an incentive as I discuss below. This would be true even if the Transco auctioned off expansion FTRS, as alluded to above. Auction proceeds in excess of Transco's cost would be a rebate to embedded cost charges for all customers.

However, we do not rule out seeking market-based rate authority for new transmission service at some point in the future, when and if that is appropriate.

Q. WHO FINANCES A MARKET-FUNDED EXPANSION?

A. Except in the case of lump sum payments, market-funded expansions will be financed by the Transco.

Q. WHO OWNS THE FACILITIES THAT ARE MARKET-FUNDED?

A. The transmission owner who is paid to build them. The funding party receives the rights, whether they are financial or physical rights. It does not receive title to the assets. In other words, market-funded transmission is not the same as merchant transmission, in which a third party permits, constructs, owns and operates a piece of the grid. Limitations on use of eminent domain, among other issues, appear to make merchant transmission projects difficult at this time except in specialized circumstances.

Q. IS MARKET FUNDING THE ONLY WAY THAT TRANSCO WILL INVEST IN THE GRID?

A. Absolutely not. Not all grid investments can or will be funded in this way. Investments to maintain the current reliability of the grid will be funded through ratebase additions. In addition, some economic investments may be funded through rates. Very large upgrades that eliminate congestion may be difficult to fund through the sale of transmission rights, because the rights will become less valuable as a result of the upgrade. But such upgrades may be economic because they increase the effective size of the wholesale market and reduce the delivered price of power. Entergy expects that such investments will be funded through Transco rates.

Entergy also recognizes that such investments may be controversial, because they may affect the value of generation. Generation developers may argue that they will not put private capital at risk if the value of their investment can be

undercut by a Transco that can build new transmission, put the cost in ratebase and recover the cost through a tariff. However, under the RTO Partnership arrangement with SPP, all rate-funded transmission investments by Transco must be reviewed by SPP as part of its regional planning process. All interested parties will have an opportunity to participate in that process.

Q. HOW DOES YOUR DESCRIPTION OF MARKET-FUNDED EXPANSION COMPARE TO MR. BARTLETT'S CATEGORIES?

A. In Mr. Bartlett's testimony, he refers to four categories of planning projects: mandatory, reliability, infrastructure and customer-initiated. To avoid confusion, it should be noted that the "reliability" category includes projects to accommodate network load growth and integration of new network resources. In my discussion, those types of projects would be candidates for market-funding, as would the "customer-initiated" category. The "mandatory" and "infrastructure" categories would be rate-funded.

Q. WILL TRANSCO HAVE AN INCENTIVE TO OVERBUILD TRANSMISSION IN ORDER TO BUILD ITS RATEBASE?

A. No, it will not. I know that this is a concern that has been raised about for-profit transmission companies in general. In my view, this concern is unfounded. With respect to market-funded expansion, which the Company expects will comprise a significant portion of total transmission expansion, it is not possible to build

"unneeded" transmission, because the only projects that go forward are those that market participants are willing to fund in exchange for the FTRs. As for rate-funded expansion, I have already noted the regional planning review process that will occur under SPP's auspices for any rate-funded project. This open review process, together with the obligation to prudently manage the construction of the upgrades provides protection against overbuilding.

Indeed, the more serious problem is the possibility of underbuilding transmission. There are many disincentives to transmission expansion – siting, timing, low return compared to other investment opportunities within utilities. Perhaps the most serious impediment is that the real benefit of a more robust transmission grid is a more robust wholesale market – which is not something that will bring direct financial benefit to the transmission owners who are expected to finance the expansion.

A Transco structure removes transmission investment from competition against other investment opportunities within a utility and allows for direct access to capital markets. However, the other obstacles remain. So long as transmission is a cost-of-service business, the real economic benefits of expansion will flow to others. If we want robust regional power markets, we will need economic investment in transmission. For this reason I favor incentives to encourage the Transco to pursue expansion opportunities, whether they are market- or rate-funded. The Transco is in the best position to identify such opportunities and it should have a positive incentive to do so.

Q. WHAT EXPANSION INCENTIVES WILL TRANSCO PROPOSE?

A. Although the details will depend on the specifics of the model that is ultimately adopted for the SPP RTO, the basic concept is that Transco would be entitled to a success fee for market-funded investments. The fee would consist of a small percentage of the value of the rights that were created by the expansion. Transco would not hold these rights for its own account, but would sell them on a long-term basis. For rate funded expansions, a higher allowed ROE and alternative cost recovery mechanisms are among the options being considered.

Q. HOW WILL A LICENSE PLATE RATE STRUCTURE AFFECT TRANSMISSION EXPANSION?

A. Before I answer that, let me explain license plate rates. SPP has a license plate rate structure, as do many of the operating ISOs. Transactions scheduled under the SPP regional tariff that sink inside of SPP pay a rate for the embedded cost of the system based on the revenue requirement of the TO whose zone they sink in.[12] Transactions through and out of SPP pay a single average rate regardless of where they originate. This structure is an alternative to so-called postage stamp rate structures. Like a postage stamp rate, it is designed to eliminate "pancaking" among multiple TOs in an RTO, but avoid the cost shifting among transmission customers that can occur under a postage stamp regime.

[12] This is called a license plate structure because a customer that pays one "home" rate can schedule from anywhere within the SPP system. It is analogous to paying for an automobile license

If Transco is part of the SPP RTO tariff, it will have one or more license plates within SPP.[13] Although it may seem incongruous for a Transco to have different license plates for its assets when it could be thought of as having a single revenue requirement, the purpose of the license plate structure is to avoid cost shifting among transmission customers, in particular the predecessor utility owners of the transmission assets.

Q. UNDER A LICENSE PLATE STRUCTURE, WHO IS RESPONSIBLE FOR CAPITAL EXPENDITURES?

A. It depends on whether you are talking about an ISO or a Transco. In a Transco structure, the Transco is responsible for financing capital expenditures on the systems that it holds (except in cases where financing is provided by market participants.) If the investment is to be rate-funded, Transco will determine, subject to regulatory review, how to apportion the responsibility among its license plate rates. Presumably, the cost of "backbone" expansions would be apportioned to all license plates. If these rate-funded expansions are substantial, over time the license plate rates within the Transco will slowly converge. If the Transco has systems under operating agreement, those transmission owners will be responsible for investments in their own systems, but Transco will finance backbone expansions that connect to their systems to the extent that the property rights can

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plate in one state and having access to every highway and byway in the country as a result.

[13] Transco will be a zone within SPP for purposes of calculating out and through transmission rates. Entergy's operating companies will pay a license plate rate within Transco. As more TOs join

be clearly delineated.

In an ISO structure, such as the non-Transco part of SPP, individual TOs are responsible for all capital expenditures. This raises the question of how to apportion responsibility for the cost of rate-funded investments. For backbone investments, some formula such as load ratio share would appear to be needed, but the question of who has the authority to set that formula is an open one. For more localized investments, the question is more complicated. If one TO must spend money to integrate a new network resource for a network load located in another TO's zone, how is the first TO compensated? If the cost goes into the first TO's license plate, then its customers are paying for someone else's service. There are several ways to mitigate this, but Entergy believes that the best solution is to eliminate the problem through a market-funding mechanism. That way, the first TO is compensated by the requesting party. This is consistent with the market structure that Entergy believes should be adopted for the region.

III. HYBRID MODEL

Q. WHAT MARKET STRUCTURE WILL TRANSCO UTILIZE IF IT IS PART OF THE SPP RTO?

A. SPP has undertaken an initiative to develop a regional market structure based on a so-called "hybrid" design. Under the types of hybrid designs being considered, the

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Transco, they will have their own license plates. This will be true whether they lease or transfer assets to Transco or whether they commit their assets under an Operating Agreement.

RTO would operate a real-time market that would use LMP to price balancing energy and transmission congestion. Transmission rights – flowgate rights (FGRs) and/or FTRs -- would be available to support transactions scheduled in forward energy markets.

Q. WILL THE HYBRID MODEL SATISFY ENTERGY'S OBJECTIVES FOR MARKET DESIGN IN ITS REGION?

A. The first thing that needs to be said about the hybrid model is that it is still under development and its ultimate design is unknown. For this reason, Entergy does not know at this time whether the model that ultimately emerges will provide an acceptable structure that will meet the objectives it believes are critical for this region. That said, the agreement in principle that was reached this summer does give us some view of the basic design elements, and they are ones that Entergy supports.

Q. PLEASE EXPLAIN THE DESIGN ELEMENTS.

A.

- First, the real-time market will operate on LMP principles, with nodal pricing for generators. Nodal prices will be aggregated to a zonal price for load balancing charges, although loads will have the option of being charged the price at their node. The details of how such a market will operate on a regional basis have yet to be worked out, although there

appears to be broad agreement that there will be a regional market operator at the RTO level.

- Second, all participants will be subject to balancing charges in the real-time market to the extent that their injections or withdrawals do not match their forward schedule. Participants scheduling transactions will be subject to congestion charges as well, based on LMP principles.
- Third, tradable transmission rights will be available to allow market participants to hedge congestion in forward markets. No rights will be needed in order to schedule a transaction. Thus the hybrid is not a "pure" physical rights model. However, the definition of these rights and the settlement rules for parties holding such rights remain open design issues.

Q. GIVEN ENTERGY'S SUPPORT FOR THE BUILDING BLOCKS OF THIS MODEL, WHY IS ENTERGY SO CONCERNED ABOUT THE DETAILS?

A. There are many important design questions that have not yet been resolved with respect to this model, and the details matter. That said, I want to emphasize that Entergy is firmly committed to working with SPP to develop an acceptable regional market model, and is optimistic that one will emerge from the current SPP process.

Q. WHAT ARE THE "DETAILS THAT MATTER" THAT HAVE NOT YET BEEN RESOLVED?

A. In Entergy's view, some of the important unresolved details involve the definition of transmission rights, the role that the RTO would have in issuing and supporting those rights, and the settlement rules that will apply to rightsholders. Entergy believes it is important to resolve those design issues in a way that minimizes "socialization" of congestion and provides a clear path for an equitable conversion plan for existing firm customers. Entergy believes that a number of other market participants share these objectives.

Q. YOU SAID EARLIER THAT THE HYBRID MODEL MAY INVOLVE FLOWGATE RIGHTS. WHAT ARE FLOWGATE RIGHTS?

A. Flowgate rights (FGRs) are transmission rights that cover specific network elements or groups of elements that constrain transmission to a "commercially significant" extent. Parties wishing to hedge congestion charges through FGRs must identify the flowgates their transaction will flow over, and how much of the transaction will flow over each flowgate. The fraction of a given point-to-point transaction that will flow over a given flowgate is called the shift factor or transmission distribution factor (TDF). TDFs tables show the shift factor for a given transaction over each identified flowgate. If a 100 MW transaction from A to B has a TDF factor of 20% on flowgate 1, that means 20 MW will flow over flowgate 1, and the transacting party would need 20 MW of FGRs on flowgate 1 to be hedged against congestion on that flowgate.

In the context of the "hybrid" model being developed at SPP, FGRs would

have some but not all of the characteristics of physical rights. They would likely be defined as options, not obligations. On the other hand, since no right is required in order to schedule, the consequence of not holding an FGR is a financial charge for congestion. In this sense FGRs would not by physical rights in the strict meaning of the term. It is not clear whether FGRs would be subject to a use-it-or-lose-it rule.

Q. WHAT ARE ENTERGY'S CONCERNS ABOUT FGRs AND SOCIALIZATION OF CONGESTION COSTS?

A. The flowgate model requires a regional transmission provider to identify ahead of time (1) the flowgates that are likely to be congested (commercially significant flowgates or CSFs); (2) the capacity of those CSFs; and (3) the TDFs for all transactions across those CSFs. Since the RTO will sell forward flowgate rights based on its assessment of CSFs, the viability of the model rests on a key premise: that the CSFs, their capacity and their TDFs will remain stable over time. There is an intense debate within the industry right now as to whether this premise is true. [14]

If the premise is not true, then socialization of costs is an issue. If the actual conditions on the grid change after the FGRs are issued, then forward

[14] A particular concern is the stability of TDFs over time. The TDFs that are actually relevant for system operations may be post-contingency TDFs – those that would result if a generation or transmission contingency were to occur. Since the contingency that constrains the dispatch may change frequently, that means the relevant set of TDFs for operational purposes may also change frequently. As explained in the next paragraph, any difference between the TDFs used for FGR definition and the actual operational TDFs can cause residual congestion.

schedules that are submitted to the RTO that are "covered" by FGRs – and thus supposed to be hedged against congestion – may turn out to be infeasible. For instance, if actual TDFs are different than the TDFs that were designated by the RTO, then the covered schedules may cause overloads on the CSFs. If other, non-designated network elements turn out to be close to their limits, then the covered schedules may cause congestion on those elements. In either case, the RTO will be required to take action -- by redispatching generation or even buying back FGRs. These actions will have a cost, referred to as a residual congestion cost.

If the residual congestion cost is charged to parties submitting schedules "covered" by FGRs, they will find that the transmission rights they held were not very good congestion hedges. On the other hand, if the settlement rule is that the residual congestion costs will be recovered through an uplift charge to all load, then we may have created a large socialization problem.[15]

Q. ARE THERE OTHER CONCERNS ABOUT SOCIALIZATION WITH RESPECT TO A FLOWGATE MODEL?

A. Yes, there are additional concerns relating to TDFs. When FGRs are issued, the set of TDFs associated with each flowgate can be defined on a point-to-point basis, or it can be defined on a zone-to-zone basis. This is a design choice. If

[15] In contrast, in an LMP/FTR model, all transactions are charged for point-to-point congestion, taking into account the effect of a transaction on all network elements. Thus redispatch cost is charged to the cost-causative customer, and there is no "socialization" of redispatch cost. FTRs provide a full hedge against point-to-point congestion. The exception to this is line outages, which can create "revenue inadequacy" -- an inability to pay FTR holders in full. Depending on the

TDFs are defined on a zone-to-zone basis for FGR purposes, then the FGRs can be used to "cover" transactions from any generator in the injection zone to any load in the withdrawal zone. This flexibility makes the FGRs useful for marketers who trade positions frequently.

However, actual schedules submitted to the system operator will be point-to-point (from POI to POW) and actual shift factors across each flowgate will differ depending on the POI and POW for the transaction. Put another way, actual TDFs are point-to-point specific. Therefore, the use of zone to zone TDFs for purposes of FGR definition would again create the possibility that schedules "covered" by FGRs turn out to be infeasible, due to the actual generator and load location. As noted earlier, FGR infeasibility requires the transmission provider to step in and buy back rights or redispatch other transactions, thus incurring costs which may be socialized in order to hold harmless the FGR holders.[16]

As I mentioned, SPP has not determined what the settlement rules would be in such a situation, or indeed whether it will even issue FGRs with zone-to-zone TDFs. But I have outlined Entergy's concerns in order to demonstrate the importance of the details on the hybrid model that have not yet been worked out.

Q. WHY IS ENTERGY CONCERNED ABOUT SOCIALIZATION OF

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settlement rule, this cost may be socialized. Line outages create a similar issue in a flowgate rights model.

[16] The transmission provider may also ensure FGR feasibility in this situation by issuing few such FGRs, to ensure that the rights that are issued are always feasible. This "derating" approach would minimize the risk of socialization but would shrink the available pool of rights, thus defeating the purpose of supporting market liquidity.

CONGESTION COSTS?

A. There are several reasons. First, by excusing transmission customers from a portion of the congestion associated with their transactions, the objective of providing efficient price signals regarding the consequences of transmission use may be compromised. When residual congestion is recovered through uplift, transmission users do not see the full economic consequences of their transmission use. If the magnitude of the residual congestion is significant, this could represent a serious problem. Further, because some "covered" transactions may cause relatively little residual congestion while others may cause a lot, a rule that residual congestion is socialized may in effect discriminate in favor of some parties and against others.

Second, socialization of residual congestion may undermine the market design goal (and Order No. 2000 objective) of giving economic price signals for new generation location decisions. If a portion of the congestion associated with a new generator is socialized through uplift, an inaccurate price signal is being sent. Likewise, when a new generator would reduce congestion on non-commercially significant flowgates that is being recovered through uplift, an inaccurate price signal is also being sent.

In addition, Entergy is concerned that a model which has the potential to create a large amount of congestion costs that must be recovered through an uplift charge, in order to support trading activities, will create an unpredictable and possibly unacceptable cost-shift to load serving entities.

Q. ARE THERE WAYS TO MINIMIZE SOCIALIZATION OF CONGESTION COSTS UNDER THIS MODEL?

A. Yes, but they have tradeoffs. As I mentioned earlier, a settlement rule that charged residual congestion directly to the cost-causative transaction would reduce socialization but it would also decrease the effectiveness of FGRs as congestion hedges. Another approach would be to try to minimize residual congestion by frequently updating the designation of CSFs and TDFs, say monthly. But this approach would limit the time frame in which congestion could be hedged and transmission price certainty could be obtained. It could also complicate our ability to put in place an effective conversion plan for existing firm transmission customers.

Q. HOW WOULD THIS APPROACH COMPLICATE CONVERSION OF EXISTING CUSTOMERS?

A. If existing rights are converted to FGRs as of the day of changeover, then an existing customer will receive an initial basket of FGRs which replicates its existing rights as of day one, based on the initial designation of commercially significant flowgates and TDFs across those flowgates. But if new flowgates are designated monthly, and if TDFs are reset, then the initial allocation of FGRs will no longer mimic the original service. If the goal of fair conversion is to give existing firm customers FGRs equivalent to the rights they have at the time of the changeover,

some mechanism to grant them a revised basket of FGRs every month must be developed or the initial conversion plan will be incomplete, because existing customers would be forced to bear the risk of changing CSFs.[17]

Q. IS THERE ANOTHER APPROACH TO FGRs WHICH WOULD MINIMIZE SOCIALIZATION BUT AVOID THE TRADEOFFS YOU IDENTIFIED?

A. Another approach that would sidestep many of the concerns I outlined above would be to have the regional transmission provider issue FTRs only, and let private market makers issue the equivalent of FGRs. I understand that this approach is an option under consideration at SPP.

Q. PLEASE EXPLAIN HOW A STRUCTURE WOULD WORK.

A. In such a structure, the regional transmission provider would be responsible for defining a set of point-to-point FTRs for the transmission grid. These could be in the form of options or obligations, but would have to be simultaneously feasible. These FTRs would be made available to participants either through an allocation or auction. Any market participant would be free to buy or sell FTRs.

A private market maker who believed that FGRs would be better received by the market would identify its own set of CSFs and issue FGRs for these CSFs,

[17] This is true even if the conversion plan is "flash-cut". Under this approach, existing customers have a one-time entitlement to the equivalent of their existing firm service, denoted in a new currency – transmission rights. Beyond this initial distribution, they are not entitled to any ongoing allocation of rights as their load grows or their supply patterns change. But if new FGRs are designated regularly, the initial set of rights they received will be devalued unless it is constantly refreshed.

and run an independent market for trading its FGRs. It would be the responsibility of the FGR market maker to determine the FGR settlement rules with its customers.

For its part, the RTO would publish and regularly update a complete list of all flowgates on the system, including information on TDFs for the flowgates. The RTO would bill transmission customers for actual congestion. The private settlement rules between the customer and the FGR market maker would determine who was responsible to pay the RTO congestion bill. The FGR market maker would also decide what mix of FTRs to hold (if any) so as to hedge the FGR obligations it created.

Such an approach would address the concerns I expressed earlier – it would avoid the problem of socialization of residual congestion costs and provide the basis for an effective conversion plan for existing firm customers. In my view, it would fully meet Order No. 2000 requirement's for market design and congestion management.

Q. WOULD THERE BE A DAY-AHEAD MARKET UNDER THIS APPROACH?

A. Entergy believes that there should be a day-ahead market, along the lines of the PJM market. Settlement of FTRs would then be against the day-ahead market price. Settlement of FGRs could also be against the day-ahead market, or if preferred by the private FGR market maker, against the real-time market. A day-ahead market would provide market participants a greater degree of price certainty

as well as allowing them to lock in transactions day-ahead and plan for unit commitment and, for customers with flexible consumption, load levels for the following day.

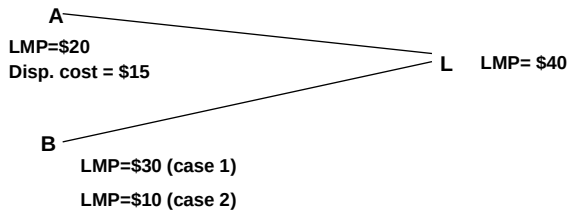
Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

FIGURE 1

FTRs Provide a Flexible Hedge

• A load holding an FTR from generator A can use it to hedge other transactions.



• If the generator at A trips, or if power is cheaper at B, holders of FTRs do not have to sell them in order to provide a partial hedge:

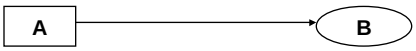
- **Case 1: $30 + $10 - $20 = $20**
- **Case 2: $10 + $30 - $20 = $20**

• In a "physical rights" model you would need to trade rights in order to change schedules – sell one physical right; buy another.

FIGURE 2

FTRs as Obligations – Negative FTR issue

• Suppose load owns a generator at A with an obligation FTR from A to B.



Case 1: LMP=$30 LMP=$40

Case 2: LMP=$40 LMP=$30

Case 1:

dispatch cost	**25**
congestion	**10**
FTR rent	**(10)**
net cost	**25**

Case 2:

dispatch cost	**25**
congestion	**(10)**
FTR rent	**10**
net cost	**25**

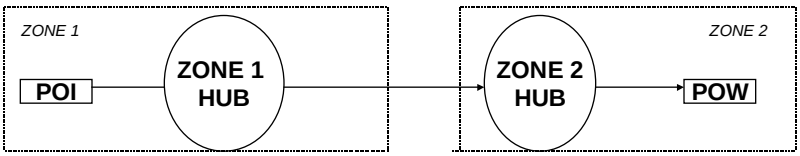
• In both cases the net cost to load is its delivered cost at A.

FIGURE 3

FTRs Can be Zone-to-Zone

•One concern is that FTRs are "custom" instruments, because they are defined from a POI to a POW.

•However, they can be decomposed into "hub and spoke" configurations, with hub-to-hub FTRs traded widely.



•Under this approach, intrazonal congestion is not socialized. Parties scheduling actual delivery can hedge intrazonal congestion with the "stub" FTRs.

AFFIDAVIT

STATE OF LOUISIANA)
)
PARISH OF ORLEANS)

MICHAEL M. SCHNITZER, being duly sworn, deposes and states: that the attached are his sworn direct testimony and exhibits and that the statements contained therein are true and correct to the best of his knowledge, information and belief.

Michael M. Schnitzer

SWORN AND SUBSCRIBED BEFORE ME,
this 12th day of October, 2000.

Notary Public

My Commission Expires: upon my death

MICHAEL M. SCHNITZER

Michael Schnitzer is a Director of The NorthBridge Group. He has over 20 years of experience in management consulting to clients in regulated industries, with a primary focus on the electric industry. Helping clients develop and implement competitive restructuring plans is central to Mr. Schnitzer's recent work for electric utility clients. He has developed initiatives in marketing, pricing, regulatory relations and supply planning and has broad experience in utility reorganizations.

Mr. Schnitzer has been an expert witness in a number of regulatory proceedings involving electric industry restructuring, utility supply planning, and environmental issues. He has testified before or submitted affidavit testimony to the Federal Energy Regulatory Commission, the Arkansas Public Service Commission, the Delaware Public Utilities Commission, the Indiana Utilities Regulatory Commission, the Maine Land Use Regulatory Commission, the Maine Public Utility Commission, the Maryland Public Utility Commission, the Massachusetts Department of Public Utilities, the New Hampshire Public Utility Commission, the New Mexico Public Service Commission, the New York Public Service Commission, the Ohio Public Utility Commission, the Pennsylvania Public Utility Commission, the Rhode Island Public Service Commission, the Public Utility Commission of Texas, the Vermont Public Service Board, and the Wisconsin Public Service Commission. He is a former adjunct research fellow at the Energy and Environmental Policy Center, John F. Kennedy School of Government, Harvard University. Before joining NorthBridge, Mr. Schnitzer was a Managing Director at Putnam, Hayes & Bartlett, Inc., where he co-directed the firm's regulated industry practice.

Mr. Schnitzer received an A.B. in chemistry, with honors, from Harvard University, and an M.S. in management from the Sloan School, Massachusetts Institute of Technology.