**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**GRIDFLORIDA COMPANIES**

**PREPARED DIRECT TESTIMONY OF MARK A. ROSSI**

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## I. Introduction

**Q. Please state your name and occupation.**

A. My name is Mark A. Rossi and I am a Managing Director in the management consulting firm of Barker, Dunn & Rossi, Inc.

**Q. Please briefly describe your educational background and business experience.**

A. I have worked in the electricity industry for over 17 years. I earned a Bachelor of Science degree in Electrical Engineering at Lafayette College. Prior to forming BDR in 1997, I worked at the PJM Interconnection Office as an operations engineer and later moved on to work with several consulting firms, all related to the electricity industry. For the past 10 years, I have been working almost exclusively with clients on issues and strategies related to electricity markets, market design and market implementation. I have worked with clients in all sectors of the industry, including electric utilities, independent power producers, and independent system operators throughout the United States and abroad. Within the United States, I have worked on electricity market design efforts in jurisdictions such as Arizona, California, Florida, Mid-Continent Area Power Pool, New England, Nevada, Oklahoma, PJM, and Texas. Internationally, I have worked on electricity market design and implementation matters in jurisdictions such as Victoria, Australia and South Australia, the National Electricity Market of Australia, Alberta and Ontario, Canada, Ukraine, Venezuela, India, China and Thailand. I also served as the first Chairman of an independent Market Surveillance Committee in Alberta, Canada.

**Q. What are the major features of the GridFlorida market design proposal that you will discuss?**

A. The major features of the GridFlorida market design can be grouped into the following broad categories:

1. The use of Locational Marginal Pricing (LMP) as the energy pricing mechanism.
2. The use of financial transmission rights rather than physical transmission rights.
3. Modifications to the day-ahead scheduling process, including the addition of a day-ahead energy market.
4. Conforming changes to the settlements process to accommodate the addition of the day-ahead market and use of locational prices.
5. The GridFlorida proposal to use market clearing prices in the energy market rather than a pay-as-bid approach.

My testimony is organized generally in line with these categories.

## II. Characteristics of an LMP based Market

**Q. Please describe what is meant by an LMP/financial rights model.**

A. For clarity, when I use the term locational marginal pricing, or LMP, I will be referring only to that component of the GridFlorida proposal. When I refer to GridFlorida's market design or market structure, I am referring to the entire set of market design features – including the day-ahead scheduling process, the day-ahead and real-time markets, the ancillary service provisions, the LMP pricing mechanism including the use of market clearing prices, the financial transmission rights, and the market power monitoring and mitigation procedures. The term "LMP" is often interpreted to include many different aspects of a market design. It is important to understand that LMP is simply an energy pricing mechanism and is only one component of an overall market structure.

The basic principle of a locational marginal pricing based system is that the price to serve load at different locations on the system is different when the transmission system becomes constrained. Conceptually, when there is no transmission congestion on the system, all LMPs will be the same.[1] Because the transmission system is unconstrained the next cheapest available MW can be used to serve the next increment of load everywhere on the transmission system. When a transmission limit is reached, however, that next cheapest MW can no longer serve the next increment of load everywhere on the system. Another generator, with more expensive generation and in a location that will help solve the constraint, will have to be dispatched so that the system is operated reliably. In effect, this generator is now the marginal generator serving load on that side of the constraint. Thus, the marginal price to serve load at different locations on the system will now be different which will cause the LMPs to be different at different locations.

[1] For the purposes of this conceptual discussion, I am assuming losses are not incorporated into the LMP calculation.

The differences in the LMPs reflect the cost associated with resolving the transmission congestion. When congestion exists and the LMPs vary, the Regional Transmission Operator will collect more revenues from the loads on the system than it pays out to generators – it is these revenues that are then paid directly to the holders of Financial Transmission Rights or FTRs. These revenues are referred to as the congestion revenues, or congestion rents, and represent the costs of solving the transmission congestion on the system.

Financial Transmission Rights (FTRs) are the second component of the market design. FTRs allow users to achieve price certainty and protect themselves against congestion costs between specific points on the transmission system. From the participant's perspective, an FTR is a financial right to the congestion revenues between two specific points on the transmission system. Thus, by holding an FTR, entities can hedge themselves against congestion costs between specific locations on the system. Conversely, when an entity does not hold an FTR, it will not be hedged against congestion costs. FTRs are strictly financial in nature and users of the system are not required to hold any FTRs in order to schedule transactions. As discussed later, FTRs will be initially allocated to existing transmission users under GridFlorida's market design.

**Q. Please briefly describe how LMP prices are calculated.**

A. Under LMP, an energy price is calculated at fixed points, typically referred to as nodes, on the transmission system. These locations, or nodes, generally include all of the substations on the transmission system that are modeled by the system operator.

There are three basic steps to calculating the LMP for each node. The first is to identify the specific resources that are eligible to set the LMPs and their applicable bid prices. The general rule is that a resource is eligible to set an LMP as long as it is not at one of its operating limits, such as its maximum output limit or its ramp limit. The second step is to define the transmission system configuration (e.g., any line outages that must be modeled) and the transmission system limits that cannot be violated. The third step is to calculate the LMPs using these two basic inputs.

By following these basic steps, the LMP at a particular location at a particular moment in time will have the following characteristics:

- The LMP at a node is the incremental cost to the system to serve one increment of load at that node. The LMP is determined using the bid prices of the eligible generators and the impact of any applicable transmission limits on the system of serving an increment of load at that node from the eligible generator(s).

- The LMP at a node is not necessarily equal to the offer of any single generator. For example, the cheapest way to serve one additional MW at Node 1 may be to use a fraction of a MW from a generator at Node 2 and a fraction of a MW from a generator at Node 3.

- A generator's bid will generally set the LMP at its node when the generator's capacity segment is only partially dispatched.

- If a generator is at its maximum output level, the LMP at its node will be determined by the bids of other generators and will be greater than or equal to the generator's highest energy bid.

- If a generator bid segment is not used at all, the LMP at its node will be less than the bid price of that segment. In other words, there is a cheaper way to serve load at the generator's bus than accepting its energy offer.

**Q. Do these principles apply to the calculation of LMPs in both the day-ahead and real-time markets? Please explain.**

A. Yes. Under the GridFlorida proposal, LMPs will be calculated in both the day-ahead market and the real-time market. These are two separate and independent sets of prices that will reflect the various bids and operating conditions in each respective market.

The day-ahead market LMPs will be calculated based on the supply and demand bids offered in the day-ahead market and a model of the transmission system. The LMPs will be calculated as described above and will reflect both the suppliers' bids to supply energy and the purchasers' bids to purchase energy. That is, the day-ahead market clears so that the LMP at a location will not be higher than the price the load is willing to pay for energy at that location.

The real-time market LMPs will be calculated based on the actual dispatch and transmission system conditions that took place in real-time. The system will be dispatched in real-time using the self-schedules and bid prices submitted by participants. The real-time LMPs will be calculated after-the-fact based on the actual dispatch instructions issued by GridFlorida and will, therefore, reflect the impacts of any congestion that occurred in real-time.

**Q. Are these LMPs market clearing prices?**

A. Yes. The LMP at a node is the market clearing price at that node. GridFlorida's proposal to calculate the LMPs based on the market-clearing price at each location is consistent with the implementation of LMP based markets in every other jurisdiction where such a market exists or is proposed to exist. The markets in PJM and New York both set the LMP at the market clearing price of each location. Similarly, the recent proposals by the SeTrans RTO, the MidWest ISO and New England will calculate the LMPs as the market clearing price at each location.

The last section of my testimony discusses the use of market clearing prices versus a pay-as-bid approach.

## III. GridFlorida's Proposal to Use Financial Transmission Rights

**Q. Please describe the nature and purpose of Financial Transmission Rights.**

A. As I discussed earlier, FTRs are the mechanism by which users can protect themselves against congestion costs between specific points on the transmission system. The key features of FTRs can be summarized as follows:

- An FTR is expressed as a 1 MW financial right between two specific nodes for a specific term. FTRs will be unidirectional.

- FTRs entitle the holder to be paid the difference between the locational prices at the points of withdrawal and injection when that difference is positive. FTR holders will be obligated to make payments when the difference in these locational prices is negative.

- All participants will be responsible for the full congestion charges associated with their transactions. In this way, the GridFlorida proposal will treat all transactions, spot market and bilateral transactions, comparably. Participants that hold FTRs will receive a credit against the congestion charges assessed to their transactions.

**Q. Under the GridFlorida proposal, how do participants obtain Financial Transmission Rights?**

A. Under the GridFlorida proposal, entities may obtain FTRs through one of three means:

- The annual FTR allocation process, which allocates FTRs to existing long-term transmission users;
- The annual FTR auction; and
- Monthly auctions.

Under the GridFlorida market design, existing transmission users will be allocated FTRs through an annual allocation process. The initial allocation process will be subject to the simultaneous feasibility test as described below. Under the GridFlorida market design, these users will not be required to go into the auction to receive their initial set of FTRs nor will they be required to make these FTRs available for sale in the auctions.

Once this annual allocation process is complete, GridFlorida will conduct an annual auction in which parties may buy and sell FTRs. Similarly, GridFlorida will conduct monthly auctions in which any additional FTRs that can be made available seasonally or monthly will be made available. Holders of annual FTRs (acquired through either allocation or auction) can sell those FTRs, buy more FTRs and possibly reconfigure them in these monthly auctions.

The annual auction and monthly auctions may be thought of as residual auctions. The annual auction, for example, will use the set of FTRs that is initially allocated as the baseline. Parties may buy and sell additional FTRs so long as they are simultaneously feasible with the set of allocated FTRs.

**Q. Please briefly describe how GridFlorida determines how many FTRs can be allocated or sold in an auction?**

A. A critical condition to the use of FTRs is that all FTRs outstanding at a given time must be simultaneously feasible. A set of FTRs is said to be simultaneously feasible if the transmission system can accommodate, under normal security constrained conditions, the set of injections and withdrawals represented by the FTRs. Therefore, the amount of available FTRs is dependent on the specific FTRs being modeled. GridFlorida can award as many FTRs as are simultaneously feasible, but no more.

GridFlorida will run a process known as a simultaneous feasibility test (SFT) to determine if a set of FTRs is simultaneously feasible. There are two major inputs to the SFT. GridFlorida will model the FTRs as injections and withdrawals at the appropriate nodes for the SFT. GridFlorida will also model the expected transmission system configuration as an input to the SFT. The SFT is accomplished by running a power flow simulation with these two inputs and (a) simulating the various transmission system contingencies (e.g. line outages) and (b) checking to make sure the post-contingent flows in the simulation do not violate any security limits on the transmission system.

Consider the following example. Two users request FTRs during one of the GridFlorida FTR auctions. One customer requests 100 MW of FTRs from Node A to Node B. This request would be modeled in the SFT as an injection of 100 MW at Node A and a withdraw of 100 MW at Node B. Another customer requests 50 MW of FTRs from Node C to Node B. This would be modeled in the SFT as an injection of 50 MW at Node C and a withdraw of 50 MW at Node B. Thus, the SFT would start with 100 MW of "supply" being injected at Node A, 50 MW of "supply" being injected at Node B and 150 MW of "load" being withdrawn at Node C. The SFT would then run a security analysis to determine if the modeled flows would violate any transmission system limits under a first contingency analysis. If no limits were violated, then these two FTR requests would be deemed to be simultaneously feasible and could be awarded in full as requested. If one or more limit were violated, then they would not be simultaneously feasible and could not be awarded in full as requested.

Q. **During the initial allocation process, will all existing users be guaranteed to receive FTRs so that they will be completely hedged from paying any congestion costs?**

A. No, there are no ironclad guarantees. GridFlorida can only issue FTRs that meet the simultaneous feasibility condition. As in the above example, there may not be sufficient simultaneously feasible FTRs issued to all transmission users such that they would be fully protected against all congestion costs. Thus, it is possible that one or more transmission users may not be allocated 100% of the specific FTRs it would desire to fully hedge itself against all congestion charges for every hour of every day.

Q. **Would the initial GridFlorida proposal involving physical flowgate rights also have been subject to the simultaneous feasibility test?**

A. Yes. Under the previously proposed physical rights model, the quantity of Physical Transmission Rights (PTRs) available would have been subject to the same limitations as mentioned here for FTRs. GridFlorida would have only been able to issue PTRs that met the simultaneous feasibility test.

Q. **Is there any difference in terms of who would be allocated the transmission rights under the LMP/financial rights model versus the initial flowgate model?**

A. No and this is a key point from a policy perspective. Under both the initial proposal and the current GridFlorida market design, the same set of existing users of the system would be allocated the transmission rights first. More importantly, these same set of transmission users did not have any ironclad guarantees under the PTR model that they would receive all the PTRs they desired to fully protect themselves against all congestion costs. Thus, from a policy perspective, the same users would receive similar protections under both proposals.

**Q. Can parties change the FTRs they hold?**

A. Yes. After the initial allocation to existing transmission users there will be additional FTRs made available through periodic auctions. There would be an annual auction that releases FTRs available for the full year that were not already allocated to existing transmission users, and there would also be monthly auctions for the release of FTRs made available on a shorter term (seasonally or monthly) basis. Any eligible participant may participate in these auctions. For example, an existing transmission user may decide that it only needs certain FTRs during the summer peak season. It would be free to offer certain FTRs for sale during the monthly auctions for the winter months when it does not need them. Users who are allocated FTRs or acquire them through the auctions may also trade FTRs bilaterally to other parties in the secondary market.

## IV. The Day-Ahead Scheduling Process and Day-Ahead Energy Market

**Q. Please describe the day-ahead scheduling process?**

A. The primary purpose of the day-ahead scheduling process is to provide an orderly process for participants and GridFlorida to produce a reliable operating plan for the next operating day. Participants need a process where they can schedule their own resources and coordinate the scheduling requirements associated with bilateral contract obligations to meet their requirements. Likewise, GridFlorida needs a process by which to evaluate these various self-schedules along with the bids submitted to the day-ahead energy market, where some users may elect to buy and sell energy. The day-ahead scheduling process combines these inputs to ensure that when taken collectively, the combined schedules for the next operating day will not violate any transmission system limits. To the extent GridFlorida could not accommodate all requested schedules due to transmission system limits, procedures will be developed to establish an equitable scheduling process under these circumstances.

**Q. Explain in general terms how the day-ahead market works?**

A. The day-ahead market is a voluntary energy market that reconciles offers from generators to supply energy and bids from users to buy energy with the goal of meeting that bid-in demand at the least cost from suppliers.

The major inputs to this process include:

(i) Suppliers and purchasers submit their bids defining the offers to supply and bids to consume prior to the start of the day-ahead energy market. These bids to supply and purchase energy are submitted relative to a specific location and a specific set of hours. For instance, a load may be willing to purchase up to 75 MW of energy at its location in any hour between 6 am and 8 pm if the price is less than $40/MWh in an hour. Similarly, a generator would submit its bid price to supply energy to the market at its locations. This bid price would be in the form of a bid price curve that specifies the price at which the generator is willing to sell specific blocks of output.

(ii) Transmission system constraints, including system limits, external interface limits and credible contingencies that may constrain generator outputs or may require a minimum amount of generation or reserves in an area.

(iii) GridFlorida's demand forecast for the next operating day.

(iv) Information about resources participants wish to self-schedule for their own use or in association with bilateral contracts. While these resources would not be participating in the day-ahead energy market per se, the fact that they wish to operate must be taken into account in the day-ahead energy market.

**Q. What are the outputs from the day-ahead scheduling process?**

A. The outputs of the day-ahead market will be the following:

(i) A set of schedules for generators that will define their scheduled commitments that are financially binding to provide energy at a specific location for specific hours.

(ii) A set of "schedules" for demands that will define their financial commitments to purchase a specified quantity of energy at a specific location for specific hours.

(iii) LMPs for each hour of the day. These LMPs are used to settle the scheduled energy purchases and sales above and are also used as the basis for the FTR settlements.

**Q. What if a participant does not want to participate in the day-ahead market? How does it schedule its resources?**

A. As I stated before, the day-ahead energy market is voluntary and therefore a participant does not have to purchase or sell energy in that market. That participant would, however, have to coordinate the commitment of its resources with GridFlorida to ensure that it would not cause any system reliability or security problems. In fact, all participants must coordinate the scheduling of their resources with GridFlorida whether or not they participate in the day-ahead energy market.

**Q. Will the LMPs all be the same in the day-ahead market?**

A. Nodal prices would not necessarily be all one price in the day-ahead market. It is possible that the locations of the various bids to supply and bids to purchase and self-schedules could cause congestion in the day-ahead energy market. If, in order to meet the bid-in demand, resources can be scheduled to resolve congestion while still being able to serve the demand at the price it is willing to pay, the LMPs would reflect this schedule and would vary by location. If, however, all of the bid-in demand can be met with the offered resources and no congestion would occur, then the day-ahead prices would be the same across the system.

**Q. Do entities that hold FTRs have to pay congestion charges in the day-ahead market?**

A. As long as a participant's day-ahead energy schedules coincide with the FTRs it holds, it would not be exposed to congestion costs. It would, however, be responsible for congestion costs for schedules to different places or from different resources or at quantities greater than its FTRs. But even in that case, the participant would still have a partial hedge. An FTR holder receives the congestion revenue for the FTRs it holds whether or not it schedules between those FTR points so the revenue is independent of the schedule. The FTR revenue and the congestion costs may not match up and may only provide a partial hedge or, alternatively, provide excess revenue. For example, suppose a customer holds FTRs from Node A to Node B. Yet, in the day-ahead energy market for tomorrow it schedules a transaction from Node C to Node B. That customer would receive the congestion revenues, if any, for the FTR it holds between Node A and Node B. However, the customer would be responsible for paying any congestion charges, if any, between Node C and Node B. Thus, the revenue the customer receives for its FTR would at least partially offset the congestion charges from Node C to Node B.

**Q. Must an entity hold FTRs in order to schedule transactions in the day-ahead market?**

A. No. FTRs are not required for any schedule – FTRs simply provide protection from congestion costs for entities that hold them. Parties are free to schedule with or without FTRs.

**Q. Please explain what it means to say a participant may self-schedule a resource?**

A. There is a basic premise that parties are free to operate their resources in a manner that they believe best meets their commercial needs so long as this operation does not jeopardize system security. However, these parties will also be responsible for any congestion charges associated with their self-schedules.

Literally, self-scheduling a generator means that a participant wants to commit and run a generator at a specific output level for a specific set of hours, and it is indifferent to the prevailing market prices. Under the GridFlorida market design, all parties are free to self-schedule their resources both in the day-ahead energy market and during real-time operations. There are two primary characteristics of a self-scheduled resource:

- The self-scheduling generator is not eligible to set the LMP in either the day-ahead energy market or the real-time market at its location for the self-scheduled MW it has scheduled to run.
- From a scheduling and operations perspective, the self-scheduled generator will be scheduled at least at its self-scheduled MW level in the day-ahead energy market and will be operated in real-time at least at its self-scheduled MW level. GridFlorida will not back down these resources below their self-scheduled values unless there is simply no other alternative to relieving a system security constraint.

**Q. Are ancillary services scheduled during the day-ahead scheduling process?**

A. Yes. GridFlorida will schedule ancillary services as part of the day-ahead scheduling process. Additionally, parties will be allowed to self-schedule their requirements for some ancillary services instead of relying on GridFlorida.

**Q. What happens once the day-ahead scheduling process is finished?**

A. The day-ahead scheduling process is complete after GridFlorida has run the day-ahead energy market and implemented its procedures to protect against undue reliance on the spot market. At the conclusion of this process, GridFlorida has a secure and reliable operating plan for the next day and prepares for the real-time operation of the system. Suppliers have the opportunity to bid in or self-schedule additional generation for GridFlorida to use during the real-time operations of the system.

**Q. Describe the real-time operation of the system.**

A. The proposal for the real-time energy market is relatively unchanged from the initial proposal. Although the energy pricing mechanism has changed to LMP, the mechanism for operating the system is unchanged from the original proposal. Under the GridFlorida market design, GridFlorida will calculate LMPs for all locations on the system not just the locations of generators. The real-time LMPs will be calculated in accordance with the principles I discussed earlier in this testimony.

GridFlorida will operate the real-time market using a hierarchical control system. GridFlorida is responsible for the short-term reliability and performance of the system and will coordinate with existing control areas in the actual dispatch of the system. Existing control areas will have the option of completely turning over dispatch operations to GridFlorida or will be allowed to work under the direction and authority of GridFlorida while maintaining the actual dispatch functionality. GridFlorida will run the real-time security constrained economic dispatch as if the entire system were a single market, however. It will take into account the real-time bid prices and self-schedules submitted by participants and will send out the appropriate operation instructions to either the generators or the existing control areas to respond to. Thus, the market design includes a single area-wide market with GridFlorida having the ability to optimize operations over the entire region while still providing the flexibility for existing control areas to manage the nuances of their sub-systems should they choose to do so. Similarly, parties may also self-schedule their resources in the real-time market as I described earlier.

**V. The Settlements Process**

**Q. Please describe the overall settlements process.**

A. As described in the testimony of Messrs. Mennes, Ramon and Schuster, the GridFlorida market design is a two-settlement system. As this name implies, there are two distinct settlements: one for the day-ahead energy market and another for the real-time market.

The day-ahead energy market settlements uses the LMPs and the scheduled quantities that cleared in the day-ahead energy market as the basis for its settlements. The real-time energy market settlement is actually a deviation-based settlement. The real-time energy market settlements compares the actual supply and actual consumption of each market participant at each location to the quantity it was scheduled to supply or consume in the day-ahead market at each location. The real-time LMPs are applied to these deviations from the day-ahead scheduled quantities.

The remainder of this section reviews the settlements process for several different scenarios. It begins with a set of assumed scheduled quantities and LMPs from the day-ahead energy market and explains how users are paid or charged the day-ahead LMPs for their scheduled quantities. It also describes how FTR holders are compensated using the congestion revenues from the day-ahead energy market.

After the day-ahead energy market examples, the section goes on to show how the real-time settlements process works. That section will start with the actual MWh produced or consumed at each location and describes how these quantities are used in conjunction with the day-ahead scheduled quantities and the real-time energy LMPs to calculate the real-time settlements positions for each market participant.

**Q. Describe the day-ahead settlements process.**

A. The results of the day-ahead market are financially binding on buyers and sellers whose bids have been cleared in the market. That is, generators will be paid the applicable day-ahead LMP for energy sales scheduled in the day-ahead market, and buyers will pay the applicable day-ahead LMP for energy purchases scheduled in the day-ahead market.

Consider a simple 2-node example with generation and load at both Node A and Node B. In this example, Load B is purchasing 500 MW from Generator A and also owns 500 MW of FTRs from Node A to Node B. Given the bids into the day-ahead market, the market cleared at the LMPs shown in the table below. During this hour, congestion occurred requiring more expensive generation to be dispatched at Node B in order to meet the bid in demand requirements.

**Example 1: Day-Ahead Energy Market Results**

**Location A: LMP = $20/MWh Location B: LMP = $30/MWh**

| Entity | MW | Payments/ (Charges) | **Entity** | MW | Payments/ (Charges) |
|---|---|---|---|---|---|
| Load A | 1,000 | ($20,000) | Load B | 600 | ($18,000) |
| Generation A | 1,500 | $30,000 | Generation B | 100 | $3,000 |
| Total Revenues: | | $10,000 | Total Revenues: | | ($15,000) |
| FTR Payments | | | | | $5,000 |
| Net GF Settlements | | | | | $0 |

In this example, one entity is scheduled to consume 1000 MW of load at Node A and another entity is scheduled to consume 600 MW load at Node B.[2] A generator is scheduled to produce 1500 MWs at Node A and another generator is scheduled to produce 100 MWs at Node B. The LMPs for this particular hour are calculated based on the submitted bids of the generators and loads and are calculated to be $20/MWh at Node A and $30/MWh at Node B.

The table shows the resulting payments (positive values) or charges (negative values) that would be made at each location from the customer's perspective. For instance, the Load at A would be charged $20,000 for the load it purchases, which is the product of its scheduled load times the LMP at Node A. Similarly, the Generator at B would be paid the nodal price at B, $30/MWh for its 100 MW at Node B during this

[2] For the purpose of this example, I will assume that the entity at B self-schedules 500 MW of load at B given it has purchased 500 MW bilaterally and has purchased the additional 100 MW in the day-ahead energy market.

hour. As the table shows, GridFlorida would collect $5,000 more from the Load than it pays to the generators – these revenues are the congestion revenues and would be used to pay any FTR holders.

Recall that the Load at B is purchasing 500 MW bilaterally from the Generator at A and also holds 500 FTRs from Node A to Node B. Load B would receive $5,000 in FTR payments (500 MW of FTRs * $10/MWh price difference between points), which equals the congestion charge it would incur for its transaction. Thus, the Load at B sees a net settlement in the day-ahead market where it will only pay the bilateral contract price for the 500 MW it purchased from the Generator at A and it will pay for the additional 100 MW it scheduled at B at B's nodal price.

The remainder of this section discusses the real-time settlements process. I have organized those examples so that they use this day-ahead settlement position as the starting point.

**Q. Please describe the real-time settlements process.**

A. The real-time settlements process is based on determining all parties' deviations from their day-ahead positions. The process begins by calculating the real-time quantities of energy supplied by generators and energy consumed by loads. These real-time quantities are compared to the day-ahead scheduled quantities to determine if an entity consumed more or less or supplied more or less than it was scheduled to in the day-ahead process. To the extent sellers and buyers have deviations in real-time from their day-ahead energy market positions, such deviations would be settled at the applicable real-time LMP. Thus, a generator would pay the real-time LMP nodal price for any scheduled energy that it fails to deliver in real-time to its bid delivery point. Similarly, a buyer would be paid the applicable LMP nodal real-time price for any scheduled energy that it does not take at its bid receipt point in real-time.

Using the same two-node example from above – the following examples describe the real-time settlements process.

**<u>Example #1 – Real-Time Load is Greater than Day-ahead Scheduled Load</u>**

This example shows the real-time settlements process for the case where the load at B consumes 100 MWs more in real-time than it scheduled in the day-ahead process. In real-time, as this load increased, GridFlorida dispatched Generator B to meet the additional load in real-time. After the fact, GridFlorida calculated the LMPs based on that dispatch resulting in the LMPs shown in the table.

**Real-time production and consumption:**

| **Location A: LMP = $25/MWh** | | | **Location B: LMP = $40/MWh** | | |
|---|---|---|---|---|---|
| Entity | MW | Payments/ (Charges) | **Entity** | MW | Payments/ (Charges) |
| Load A | (1,000-*1,000*) | $0 | Load B | (700-*600*) | ($4,000) |
| Generation A | (1,500-*1,500*) | $0 | Generation B | (200-*100*) | $4,000 |
| Total: | | $0 | Total: | | $0 |

(The "Payments and Charges" are calculated as: (Real-time MWh – *Day-ahead Scheduled MWh*) * Real-time LMP).

In this case, the LMP at Node B is higher in real-time than it was in the day-ahead market because additional generation was required in real-time at a higher price than was scheduled in the day-ahead market.

**<u>Example #2 – Generator Output in Real-Time is Less than Day-ahead Schedule</u>**

This example shows the real-time settlements process for the case where the generator at A produces 100 MWs less in real-time than it scheduled in the day-ahead process. For the purposes of this example, I assume that a 100 MW generator tripped off line at Node A and the energy had to be replaced by more expensive generation located at Node B.

**Real-time production and consumption:**

**Location A: LMP = $40/MWh** **Location B: LMP = $40/MWh**

| Entity | MW | Payments/ (Charges) | **Entity** | MW | Payments/ (Charges) |
|---|---|---|---|---|---|
| Load A | (1,000-*1,000*) | $0 | Load B | (600-*600*) | $0 |
| Generation A | (1,400-*1,500*) | ($4,000) | Generation B | (200-*100*) | $4,000 |
| Total: | | $0 | Total: | | $0 |

In this particular example, the load at both locations is indifferent to the real-time prices. They are completely hedged since they scheduled their load in the day-ahead energy market. In this case, the generator at Node A must pay the LMP at its location for the 100 MW it failed to produce. The generator at Node B is paid the real-time LMP at its location for the additional 100 MW it produced.

**VI. The GridFlorida Market Design Should Include the Payment of Market Clearing Prices**

**Q. Please explain why the GridFlorida market design should include the payment of market clearing prices.**

A. The payment of market clearing prices is an essential component of the LMP model. The entire LMP methodology is based on the principle that entities be paid the market clearing price and any alternative proposal would lose the benefits of such an approach. Absent payment of market clearing prices, I believe that suppliers will guess at what the market clearing price would be in a competitive market and use those guesses as the basis for their bids into the markets. Such a bidding strategy cannot be expected to result in efficient outcomes, efficient price signals, or lower costs to retail users.

**Q. Why do you expect that supplier bids would be distorted if market clearing prices are not paid?**

A. Unlike under a market clearing price approach, where a supplier can submit a bid with the expectation of receiving a market clearing price when that price exceeds its bid, under other structures that supplier will have different expectations. For example, under a pay-as-bid approach a supplier will recognize that its profit on a sale into the market will depend on its bid price, not on the market clearing price. That supplier thus will want to bid some amount above its cost to make a profit.

The question the supplier will need to answer is what amount above its cost. The answer (absent some other bidding restriction on the supplier) will be the maximum amount above cost that it can bid and still be called-on to supply energy. This bidding strategy would result in the maximum profit to the supplier. The supplier thus would guess what that amount is, *i.e.*, the supplier would guess at the price that will clear the market and bid that amount.

**Q. What is the result of such a bidding strategy?**

A. The expected result under such bidding behavior normally would be an inefficient mix of resources used to serve load. One can reasonably expect that under a bidding strategy where suppliers are guessing at a market clearing price, some suppliers will guess wrong. When a particular supplier is a low cost supplier, but its estimate of the market price is too high, that low cost supplier will not be dispatched.

**Q. But would not prices to retail users be higher under a market clearing price regime than, for example, under an approach where suppliers are paid their bid prices?**

A. As I just explained, if market clearing prices are not paid, suppliers will guess at what they believe the market clearing price will be, and will bid that amount. Whether prices to users are higher or lower than under a market clearing price regime would turn on whether these suppliers tended to guess high, *i.e.*, tended to submit bids that exceed the market clearing price that would occur under a market clearing price regime, or tended to guess low, submitting bids that would be below the market clearing price that would occur.

While I do not believe that the costs to users can be stated unequivocally as being systematically higher or lower under a particular regime, I do believe that ultimately the inefficiencies in generation dispatch that result under an approach other than a market clearing price approach can be expected to harm retail users through higher energy costs. I also believe that it is reasonable to expect that users ultimately would be harmed from the distorted price signals that result when market clearing prices are not paid, for example, by distorted siting signals for new generation.

I also note that the testimony of Messrs. Mennes, Ramon and Schuster discusses sharing any gains from the sales in the energy markets with retail users.

**Q. Does that conclude your testimony?**

A. Yes it does.

## CERTIFICATE OF SERVICE

**I HEREBY CERTIFY** that a true and correct copy of the Prepared Direct Testimony of Mark A. Rossi has been furnished by Electronic Mail(*), Overnight Delivery(**) or Hand Delivery(***) and by United States Mail this 19th day of September, 2002, to the following:

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