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May 12, 2004

***Via Overnight Delivery***

Hon. Blanca S. Bayo, Director
Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: *Review of GridFlorida Regional Transmission Organization (RTO) Proposal*, Docket No. 020233-EI
*Comments of Reedy Creek Improvement District – Market Design Issues*

Dear Ms. Bayo:

Please find enclosed for filing in the above-referenced matter an original and fifteen copies of the comments of Reedy Creek Improvement District on Market Design Issues. A copy of this filing will be distributed on May 13, 2004 to parties in this proceeding via the GridFlorida E-mail Exploder List.

An additional copy of this filing labeled "stamp and return" also is enclosed. Please stamp the date and time on that copy and return it to me in the enclosed self-addressed, stamped envelope.

Thank you for your attention to this matter. Please do not hesitate to contact me should there be any questions.

Respectfully submitted,

/s/ Daniel E. Frank

Daniel E. Frank
*Counsel for*
*Reedy Creek Improvement District*

Enclosures

cc: Parties (via E-mail)

DOCUMENT NUMBER-DATE
05548 MAY 13 04
FPSC-COMMISSION CLERK

Comments of Reedy Creek Improvement District (RCID) – May 12, 2004

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|---|
| RCID general comments: Because the Applicants did not set forth their position on the market design issues identified below, they are in the position of being able to incorporate stakeholder views in developing their position. RCID strongly encourages them to do so. In addition, RCID supports the objectives identified at pp. 4-5 of their overview document, but notes that, in the development of plans to achieve those objectives, a comprehensive package, including details of all components of market design, must be considered (as opposed to individual components lacking detail). RCID reserves the right to supplement its comments herein, and to endorse or oppose the positions of other parties, as the issues and positions are developed. |
| **ISSUE 1**<br>**MARKET DESIGN AND CONGESTION MANAGEMENT** |

| **Market Design Issues** | **Sub-Issues/Options** | **Description** | **Comments** |
|---|---|---|---|

| Market Design Issues | Sub-Issues/Options | Description | Comments |
|---|---|---|---|
| How to Price Energy | Pay as Bid or Market Clearing Price Under Centralized Market, Bilateral Contracts, Hybrid | Pay as bid - generators committed and dispatched to serve load would be paid the price they submitted as a bid, not a market clearing price.<br><br>Market clearing price - generators that are committed and dispatched in merit order are paid the same energy price absent congestion.<br><br>Bilateral contracts - prices developed through bilateral contracts with no centralized market.<br><br>Hybrid - combination of bilateral markets and centralized markets.<br><br>**<u>RCID supports a hybrid approach because it provides more options for market participants. Any market design must allow for bilateral contracts. As to the pricing mechanism to be used in the centralized market, RCID continues to evaluate the issues, but at this time is leaning toward use of a single market-clearing price approach, assuming appropriate market power mitigation measures are in effect.</u>** | Market clearing prices provide an incentive for suppliers to develop more efficient processes to reduce costs and maximize profits.<br><br>Market clearing prices allow bids at short-run marginal costs.<br><br>Significant market power issues can arise under market clearing price structure.<br>No US markets currently use pay-as-bid.<br><br>Bilateral contracts are used in today's market in Florida, and are the basis for Entergy's recently filed "Weekly Procurement Process" ("WPP") proposal at FERC (which includes formalized procurement rules but relies on bilateral contracting).<br><br>GridFlorida physical rights proposal was a hybrid model; bilateral contracts prior to real-time operations, central market to address real-time imbalances and real-time congestion. |



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| Market Design Issues | Sub-Issues/Options | Description | Comments |
|---|---|---|---|
| | Transmission Service - Integrated or Not-Integrated With Energy Supply | When transmission is integrated with energy supply, a seller in the markets is not required to obtain separate transmission service, it only needs to submit bids in the markets to sell power. Generally, the embedded cost of the transmission grid is allocated to load, and congestion costs are allocated to bilateral transactions and transactions in a centralized market based on energy prices in that market.<br><br>When transmission is not integrated with energy supply, either the seller or the purchaser must obtain a separate physical right to use the transmission system in order to make a sale of power.<br><br>**<u>RCID continues to evaluate this issue.</u>** | An integrated approach is the approach under an LMP model with financial transmission rights.<br><br>A non-integrated approach is used today for transactions in Florida, and was used with the Florida broker. Energy markets and the right to transmission are completely separate.<br><br>The GridFlorida physical rights model was a combination: non-integrated prior to real-time (there was no day-ahead market) and integrated for purposes of delivering imbalance energy. |
| Issues Under A Central Market Approach | Market Settlements | A single settlement system includes only one market, typically a real-time (hourly) market.<br><br>A two settlement system includes both a day-ahead market and a real time-market, the latter of which typically addresses real-time imbalances and real-time congestion.<br><br>**<u>RCID supports a two-settlement system, assuming bilateral contracts remain an option.</u>** | For some time, California was a single settlement system due to the bankruptcy of the Cal-PX, which ran the day-ahead market.<br><br>A two settlement system is used in all US RTO's currently operating markets. However, in ERCOT the current day-ahead market is limited to ancillary services; a day-ahead market for energy currently is being designed. |

| Market Design Issues | Sub-Issues/Options | Description | Comments |
|---|---|---|---|
| | Nodal or Zonal Pricing | Nodal - prices can be calculated specific to each load bus and generator bus (thousands of prices).<br><br>Zonal - prices can be calculated after load and generations is aggregated into zones based on existing service territories, congestion profiles or some other method.<br><br>**RCID continues to evaluate this issue.** | In deciding between zonal and nodal pricing, customers should weigh simplified market design and administration (significantly fewer prices) against reduced price signals.<br><br>Most existing zonal markets are converting or have converted to nodal markets.<br><br>Unclear whether nodal pricing and pay-as-bid pricing can be combined. |
| | Bid Structure | Single part bids - each bid consists of one bid price ($/MWh).<br><br>Multiple bids - each bid can include multiple cost components (*e.g.*, energy, no load, start-up).<br><br>What costs should be included in bids?<br>(i)Variable costs.<br>(ii)Variable and fixed costs.<br><br>**A multi-part bid approach appears preferable because it provides for maximum information to the system operator for dispatch decisions and policing. However, RCID would like additional detail regarding how this approach is implemented (*e.g.*, are no-load and start-up costs converted to a $/MWh figure for purposes of evaluating a bid?).** | Single part bids can add complexity to developing efficient bidding strategies, and thus can lead to inefficiencies.<br><br>Multi-part bids can make it easier to police bidding behavior.<br><br>The costs that should be included in bids will depend on the energy pricing approach and the bidding rules. |

| Market Design Issues | Sub-Issues/Options | Description | Comments |
|---|---|---|---|
| | Cost Based or Market Based Bids | Cost based bids - bids based on the actual cost to supply energy and capacity. Bids could include variable costs (*e.g.*, variable O&M, fuel) and fixed costs (*e.g.*, capital costs).<br><br>Market based bids - bids based on competitive market pricing subject to applicable mitigation measures to prevent the exercise of market power.<br><br>**<u>RCID supports a market-based bid approach, but only where a competitive market has been shown to exist and is functioning properly.</u>** | Cost based bids can help alleviate market power concerns under a pay-as-bid structure.<br><br>Market-based bids provide an incentive to reduce costs to create competitive savings. |
| | Day-Ahead Bidding Requirement | Voluntary bids - no one is <u>required</u> to bid.<br><br>Partial mandatory bids - LSEs have an obligation to bring their resources to the market in conjunction with a resource adequacy requirement (such as a requirement to have a minimum amount of available generating capacity on a daily basis).<br><br>Full mandatory bids - as a condition of participating in the market, all participants must bid all of their available generation in the markets.<br><br>**<u>RCID opposes mandatory bidding requirements because various limitations on resource output (contract restrictions, environmental permit limitations, etc.) make compliance problematic. RCID supports a voluntary bidding system, so long as any market power issues (such as withholding) are resolved.</u>** | A number of factors must be considered when determining bidding requirements, including reliability, market power concerns, and equity.<br><br>All RTO/ISO-run markets have some type of mandatory bidding or scheduling requirements, either through capacity obligations or balanced schedule requirements. |
| | Limitation on Use of Real-Time Market | Could have a balanced schedule requirement as part of a day-ahead scheduling process. An LSE would have to have sufficient resources available to serve its expected load (either when scheduling occurs or coming out of the day-ahead market).<br><br>**<u>RCID notes that over-reliance on the real-time market could result in reliability problems. Whether a balanced schedule requirement can be supported depends on the thresholds to be</u>** | A balanced schedule requirement limits use of the real-time market.<br><br>A decision would have to be made on whether penalties should be established for market participants that do not |

| Market Design Issues | Sub-Issues/Options | Description | Comments |
|---|---|---|---|
| | | **<u>used in assessing penalties for failure to submit a balanced schedule.</u>** | satisfy the balanced schedule requirement when the imbalances are outside of specified thresholds. |
| Transmission Congestion Options | Financial Transmission Rights ("FTRs") | FTRs are financial rights, meaning no physical right to the transmission system is necessary to schedule energy.<br><br>Priority of use of the system is not linked to whether or not a transmission customer holds such a right.<br><br>An FTR provides the holder with a financial hedge against potential congestion charges between sources and sinks on the transmission system.<br><br>**<u>RCID continues to evaluate this issue.</u>** | FTRs are used in PJM, ISO-NE, NYISO, ERCOT, and proposed for use in MISO and later phases of SPP.<br><br>Many issues arise when developing an FTR model for transmission congestion, including:<br>(a) FTRs must be simultaneously feasible for revenue adequacy.<br>(b) Should transmission customers receive auction revenue rights ("ARRs") (*i.e.*, receive the revenues from FTR auctions) or FTRs?<br>(c) How are FTRs or ARRs allocated to existing uses of the transmission system, including existing transmission agreements?<br>(d) Should FTRs be options or obligations (*i.e.*, should the holder of an FTR be liable for congestion payments in certain circumstances)?<br>(e) How should residual FTRs be allocated?<br>(f) How should revenues from |

| Market Design Issues | Sub-Issues/Options | Description | Comments |
|---|---|---|---|
| | | | FTR auctions be distributed? |
| | Physical Transmission Rights ("PTRs") | Must have a physical right to the transmission grid to schedule energy flows.<br><br>Congestion is managed using redispatch, or when redispatch will not resolve a constraint through transmission loading relief procedures.<br><br>If no transmission capacity is available to grant a new transmission request, redispatch can be offered to grant the new service (subject to that customer paying the costs of redispatch).<br><br>**RCID continues to evaluate this issue.** | GridFlorida's March 19, 2002 filing included an example of a physical transmission rights model with redispatch service. Issues with PTRs include:<br>(a) How to define facilities with commercially significant congestion and allocate rights to those facilities.<br>(b) Determining existing customers' rights to PTRs.<br>(c) Allocation of redispatch costs to maintain previously-approved transmission service. |
| | Redispatch Service | Product offered to transmission customers willing to pay the cost of redispatch to create the counter flows needed to allow a transaction to continue or to grant a new transmission service request.<br><br>**A redispatch service product generally seems acceptable, but more detail is needed.** | Such an approach can be used under the current transmission tariff structure.<br><br>A form of redispatch is currently proposed for the Entergy area in conjunction with its WPP proposal. |
| Control Area Options | Single Control Area | An RTO would operate as a single control area and perform all NERC control area functions. | PJM, ISO-NE, NYISO, Cal-ISO. |
| | Independent Multiple Control Areas | An independent entity would operate a bilateral market (possibly including redispatch service) with existing control areas maintaining their NERC control area responsibilities. | Florida Broker.<br><br>Similar to Entergy WPP proposal. |
| | Hierarchical Multiple Control Areas | Existing control areas have option to turn-over control functions to RTO or to maintain their status as control area operator. | GridFlorida as filed.<br><br>MISO. |

| Market Design Issues | Sub-Issues/Options | Description | Comments |
|---|---|---|---|
| | | RTO responsible for short-term reliability.<br><br>Control areas responsible for regulation and frequency response functions.<br><br>**<u>RCID supports a hierarchical approach.</u>** | |
| Ancillary Services | How Provided | Could establish markets for ancillary services.<br><br>Could establish contractual arrangements for the RTO to obtain ancillary services from each control area operator on a cost-based basis, to allow the RTO to make the services available under the RTO transmission tariff.<br><br>Parties still could enter into bilateral arrangements for certain ancillary services (*e.g.*, operating reserves), including with the control area operators.<br><br>A party can self-provide certain ancillary services (*e.g.*, operating reserves).<br><br>**<u>RCID believes all of these options are generally acceptable approaches, with one exception: the RTO should be authorized to obtain ancillary services from a control area on a voluntary basis, but should not be allowed to require a control area to provide ancillary services. RCID emphasizes that a control area should have the right (but not an obligation) to self-supply ancillary services.</u>** | |
| | Types of Services Offered | Reactive Supply and Voltage Control Service.<br>Control of transmission voltage through adjustments to generator reactive output.<br><br>**<u>RCID continue to evaluate this issue, but notes that market-based pricing should be allowed only where there has been a showing of</u>** | Provided by generators at no cost (per the terms of their interconnection agreement or other contract) or could be paid for at a cost-based or market-based price. |



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| Market Design Issues | Sub-Issues/Options | Description | Comments |
|---|---|---|---|
| | | **a competitive market that is functioning properly and all market power issues are resolved.** | Could include payment for lost opportunity cost (*i.e.*, payment for reduced energy output). |
| | | Regulation and Frequency Response Service.<br>Capability of a generator to increase/decrease its output in response to a regulating control signal.<br><br>**See comment above.** | Regulating capacity could be provided by generators at no cost (per the terms of their interconnection agreement or other contract), or could be paid for at a cost-based or market-based price.<br><br>Net energy could be priced in a manner consistent with other energy bought/sold in the energy market.<br><br>Under hierarchical structure, individual control areas are responsible for dispatching Regulation Service within their control areas. An RTO could be involved in determining regulation needs.<br><br>Bid-based markets for regulation are in place today. |
| | | Energy Imbalance Service.<br>Energy provided to match deviations in schedules and actual load.<br><br>**See comment above.** | Prices could be cost-based or established through the real-time energy market. |
| | | Operating Reserves Service.<br>The amount of reserve capability required to restore tie-lines | An RTO or FRCC could establish minimum operating |



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| Market Design Issues | Sub-Issues/Options | Description | Comments |
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| | | following a contingency.<br><br>Spinning (*i.e.*, synchronized to the system) and non-spinning (*i.e.*, not synchronized to the system); 10-minute, and 30-minute increments.<br><br>**See comment above.** | reserve requirements and, if applicable, allocate to the control areas.<br><br>Prices could be cost-based or established through markets.<br><br>An RTO could establish deliverability requirements for eligible resources. |
| | | System Restoration Service.<br>Ability of a generator to start-up without the benefit of an off-site power source and go from a shutdown condition to an operating condition.<br><br>**A *pro rata* allocation of the costs of this services seems acceptable.** | An RTO or the FRCC could determine amount and locations of capability required, and certify generators as eligible to provide this service.<br><br>Transmission Customers could be allocated a *pro rata* share of the payments made to system restoration service suppliers or the costs could be allocated in another equitable manner. |
| Losses | How Losses Will be Provided | Centrally (RTO) - losses are provided by the RTO and allocated to loads by load ratio share and to through and out transactions.<br><br>Locally (control area operator) - control areas are responsible for providing the losses in their areas.<br><br>Self-Supply (Generator or Load) - transmission customers are responsible for supplying their losses. | |

| Market Design Issues | Sub-Issues/Options | Description | Comments |
|---|---|---|---|
| | | Combination - above methods could be combined.<br><br>**<u>RCID prefers the option of obtaining losses centrally or through self-supply.</u>** | |
| | Calculating Losses | Average - losses are calculated and allocated using an average loss methodology (*e.g.*, average losses generated as a percentage of load served over one year).<br><br>Marginal - losses are calculated on a marginal basis, *i.e.*, based on the next MW generated.<br><br>**<u>RCID continues to evaluate this issue, but is leaning toward use of average losses.</u>** | Use of marginal losses would raise the following issue:<br>(a) Because losses are calculated on a marginal basis, excess revenues will be collected. How are those excess revenues returned to the parties that paid for the losses?<br>(b) A reference bus to calculate marginal losses must be determined, or a distributed reference methodology must be developed to calculate marginal losses. |
| | Pricing Losses | Marginal or Average Losses - prices can be calculated as a component of LMP or priced separately.<br><br>Return-in-Kind - can require or permit transmission customers to return losses in kind.<br><br>**<u>Return-in-kind should be permitted (but not required).</u>** | |

| ISSUE 2<br>MARKET MONITORING AND MARKET POWER MITIGATION | | | |
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| **Monitoring Issues** | **Sub-Issues/Options** | **Description** | **Comments** |
| Market Monitoring Unit "MMU" | Structure of Market Monitor | Independent board - permanently established MMU with separate Board outside of RTO.<br><br>RTO staff - RTO staff performs all monitoring functions, reports directly to RTO Board (not officers).<br><br>Separate contractor - hired by and reports directly to RTO Board.<br>RTO staff with outside advisor - RTO staff performs all monitoring functions, advised by separate contractor hired to provide technical expertise, and staff reports directly to RTO Board (not officers).<br><br>FPSC - performs all monitoring functions with staff or contracted employees; RTO Board has no authority to direct actions.<br><br>**RCID prefers the as-filed independent Board approach, which also was generally supported by stakeholders.** | GridFlorida as filed includes an independent board.<br><br>Use of RTO staff can cause issues regarding perceptions of independence when the RTO is running markets. ISO-NE uses a separate contractor.<br><br>NYISO uses RTO staff with outside advisor. |
| | Funding and Budget | Submitted budget - MMU (other than contractor option or FPSC option) would submit an annual budget to RTO Board for review/approval. MMU obliged to stay within budget parameters.<br><br>Contract price (Contractor option) - RFP process, contractor selected, payments subject to contract price and provisions.<br><br>Actual costs - any annual budgets are projections only. Actual costs are recovered through RTO grid management charge.<br><br>**A budget should be established, but additional funding should be made available as needed so that the MMU can address special, unforeseen issues or problems that may arise.** | |
| | Functions | Monitors all RTO markets.<br><br>Monitors compliance with the RTO transmission tariff. | The ability of the MMU to impose sanctions or penalties would be |



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| Monitoring Issues | Sub-Issues/Options | Description | Comments |
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| | | Monitors RTO operations.<br><br>Provides reports and information to FERC/FPSC.<br><br>**<u>All of these functions seem appropriate and necessary.</u>** | dependent on including specific provisions in the filed market monitoring documents. |
| Methods of Monitoring | | Screen and impact test - PJM, NYISO, and ISO-NE all use screens and impact tests to initially identify potential market abuse. The screens are objective assessments of changes in bidding practices, quantities, schedules, or prices that are above specified threshold levels. Questionable bids identified by the screens are then subject to the impact test. If the bids did not change market prices, there is no "impact," and no need to mitigate the bids.<br><br>Other - all RTO's reserve the right to investigate any activity that they believe represents market manipulation by a market participant. They use a staff of economists, statisticians, consultants, and other professionals to monitor participant behavior and identify questionable activities, which, once identified, may be subject to mitigation or reporting.<br><br>**<u>RCID continues to evaluate this issue.</u>** | |
| Mitigation | Timing of Mitigation | Prior to posting and accepting a schedule - a market participant's actions could be mitigated prior to accepting and posting schedules.<br><br>After posting and accepting a schedule - a market participant's actions could be mitigated after accepting and posting schedules.<br><br>**<u>If an effective system is in place, detecting and mitigating problematic market participant actions makes sense, but the details and costs of such a system remain to be worked out.</u>** | If a market participant's actions are mitigated prior to accepting the schedule, the financial impact of the mitigation on the market prices are incorporated in the schedules, and reflected in the dispatch instructions.<br><br>Mitigation of the actions prior to posting a schedule may delay the posting of the schedule and impact other |

| Monitoring Issues | Sub-Issues/Options | Description | Comments |
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| | | | time-sensitive functions of the RTO.<br><br>ISO-NE mitigates bids before posting.<br><br>If a market participant's actions are mitigated after accepting the schedule, the financial impact of the mitigation is not reflected in the schedules or the dispatch. |
| | Automatic or Manual Mitigation | Automatic - all bids that fail the screen and impact tests are mitigated immediately. Market participants may challenge the mitigation to restore bids prior to final settlement.<br><br>Manual - normally incorporates the screen and impact test. But market participant has opportunity to explain apparently anomalous bidding behavior. If explanation is unsatisfactory, the bid is mitigated.<br><br>**RCID continues to evaluate this issue.** | Automatic mitigation is implemented in the NYISO.<br><br>Manual mitigation is used by ISO-NE. |
| | Mitigation Measures | Reference Price - bids may be mitigated to a reference price, typically established by past successful bids, marginal costs, or a previously negotiated reference.<br><br>Reliability Must Run ("RMR") Contracts - typically used to financially support units that are needed for reliability but are not economically dispatched. However, units that can exercise local market power may be given an RMR contract to establish their bidding within defined parameters.<br><br>Safety-Net Bid Cap - at present, all RTO's have a bid cap in place as a safety net. In almost all markets the current cap is $1,000/MWh. A bid above the bid cap will automatically be mitigated. | Financial withholding is mitigated by mitigating the bids.<br><br>Physical withholding can be mitigated by requiring certain units to be bid.<br><br>ISO-NE also has a unit-specific safe harbor bidding provision for peaking units in certain specified congested areas. It |

| Monitoring Issues | Sub-Issues/Options | Description | Comments |
|---|---|---|---|
| | | Withholding Sanctions - withholding can be financial or physical. Financial withholding is conducted by bidding a unit into the market at a price where it will not economically dispatch. Physical withholding is not bidding in a unit or making the unit unavailable through full or partial outage.<br><br>**The $1,000/MWh cap used by other markets seems excessive for Florida. In addition, customers could be significantly and adversely affected by having to pay $1,000/MWh for a long number of hours.** | calculates a reference price based on generic costs for peakers and a multiplier and does not mitigate if the unit's bid price is below this safe harbor bid.<br><br>The role of the FPSC must be determined. |

| ISSUE 3<br>RESOURCE ADEQUACY | | | |
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| **Resource Adequacy Issues** | **Sub-Issues/Options** | **Description** | **Comments** |
| Authority to Establish the Requirement | | FPSC - authority established by Grid Bill.<br><br>RTO - authority delegated by FPSC (agent).<br><br>FERC - has said it will defer to the states.<br><br>FRCC - authority delegated by NERC or FPSC.<br><br>**RCID prefers for the FPSC, not NERC, to delegate authority to the RTO. The FPSC should maintain its role in the resource adequacy area; there is no need for NERC to get involved.** | |
| Level of Resource Adequacy Requirement | | Reserve Margin ("RM") = (capacity rights – weather-normalized firm peak load + firm sales)/(weather normalized firm peak load).<br><br>Loss of Load Probability ("LOLP") - probability of not meeting firm load obligations due to capacity shortfalls, *i.e.*, standard of 1 day in 10 years.<br><br>**RCID continues to evaluate this issue.** | ERCOT RM - 12.5 percent.<br><br>MISO RM - default to state requirement or 12 percent.<br><br>NYISO RM - 18 percent.<br><br>ERCOT/NYISO /PJM/ISO-NE all use 1 in 10 LOLP.<br><br>Highly congested areas like NYC and Long Island have local resource adequacy requirements tied to energy deliverability. ISO-NE also is moving toward this type of locational requirement. |
| Availability of Markets or | | Centralized capacity market - a voluntary daily, monthly, and/or yearly market administered by an RTO or other entity to clear bids | PJM and NYISO have centralized markets. |

| Resource Adequacy Issues | Sub-Issues/Options | Description | Comments |
|---|---|---|---|
| Deficiency Auction | | offered for capacity.<br><br>Deficiency auction - RTO administered, mandatory periodic auction requiring deficient LSEs to purchase sufficient capacity.<br><br>**<u>RCID continues to evaluate this issue, but emphasizes the need to have a bilateral contract option.</u>** | NYISO has deficiency auctions. |
| Term of Obligation | | Short-term - daily, monthly, seasonal.<br><br>Long-term - 1 (rolling 12 months), 5, or 10 years.<br><br>**<u>RCID prefers the rolling 12-month term.</u>** | |
| Who Must Comply | | The RTO, with a subsequent allocation of costs to each LSE.<br><br>Each LSE in Peninsular Florida.<br><br>**<u>Each LSE should comply.</u>** | LSE includes all IOUs, electric cooperatives, municipalities, and municipal agencies (as well as their agents).<br><br>Must determine how non-RTO members will be allocated a resource adequacy requirement. |
| Enforcement | | Sanctions - to be applied after-the-fact and assigned by the RTO, FPSC, or FRCC.<br><br>Peer Pressure - deficiency reported to FERC, FPSC, or FRCC.<br><br>**<u>"Peer pressure" has worked historically, but it must be reevaluated periodically to ensure that it continues to work and, if not, to determine what other measures should be taken.</u>** | |

| ISSUE 4<br>TREATMENT OF CAPACITY MARGIN[1] | | | |
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| **CBM Issues** | **Sub-Issues/Options** | **Description** | **Comments** |
| Application in Peninsular Florida | | No CBM - no entity, including the RTO, would be allowed to reserve CBM. All capacity resources necessary to maintain reliability would have to be contained within the RTO.<br><br>Peninsular Florida/Georgia Interface - CBM allowed in ATC calculation only for the interface. Allows access to resources outside Peninsular Florida in an emergency.<br><br>All control areas - all control areas would have access to resources located in other control areas.<br><br>**RCID continues to evaluate this issue, but is concerned that reserving CBM will needlessly tie up available capacity in Florida.** | Reserving CBM at the Peninsular Florida/Georgia Interface would be similar to the practice in PJM. |
| Who Establishes CBM? | | FPSC - the FPSC could establish/certify CBM reservations as part of its assessment of LSE resource adequacy. RTO would include CBM amounts in ATC calculation.<br><br>RTO - the RTO could designate CBM for reliability or as part of an RTO resource adequacy requirement (*e.g.*, the approach used by PJM).<br><br>LSE - an LSE that is a transmission provider could designate CBM to help meet its resource adequacy criteria. The RTO would include CBM reservations in ATC calculations (*e.g.*, the approach used by some control areas outside peninsular Florida).<br><br>Combination - some combination of the above. | |

1 Capacity Benefit Margin ("CBM") is defined by NERC and the FRCC. The purpose of CBM is to allow an entity to maintain reliability with a lower amount of installed capacity than would otherwise be required. CBM takes advantage of the random nature of generator forced outages and of load diversity to access generation capacity from unspecified sources on an as-needed basis. To secure access to this generation capacity, an amount of transmission capacity is reserved during the calculation of ATC.

| CBM Issues | Sub-Issues/Options | Description | Comments |
|---|---|---|---|
| | | **<u>See comment above.</u>** | |
| Associated Transmission Rights | | Physical - reservation of CBM included in ATC calculation and would constitute a physical reservation.<br><br>Financial - reservation of CBM might or might not convey an allocation of FTRs.<br><br>**<u>See comment above.</u>** | |