# PJM Dynamic Transfer Business Rules for Generators

## Background

The NERC Glossary of Terms [i] defines a Dynamic Transfer as the provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator out of one Balancing Authority (BA) Area into another. <u>Dynamic Transfers includes both Dynamic Schedules and Pseudo-Ties, which are further defined below.</u>

The NERC Glossary of Terms [i] defines a Dynamic Interchange Schedule or Dynamic Schedule as a telemetered reading or value that is updated in real-time and used as a schedule in the Area Control Error ("ACE") equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Dynamic Interchange Schedules or Dynamic Schedules are commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.

The NERC Glossary of Terms [i] defines a Pseudo-Tie as a telemetered reading or value that is updated in real-time and used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.

The major difference between a Dynamic Schedule and a Pseudo-Tie is how they are incorporated within a Balancing Authority's ACE calculation. A Dynamic Schedule is modeled as an "Interchange Schedule" and therefore is subject to NERC Tagging requirements [iv][v][ix]. A Pseudo-Tie, modeled as a "virtual" tie, is accounted as actual interchange and requires an adequate level of modeling within the PJM Energy Management System (EMS) and PJM Market Systems depending on the obligations associated from participating in PJM markets and to ensure accurate market flow calculations required to mitigate loading on "market-to-market" flowgates. Pseudo-Ties are not currently subject to NERC Tagging requirements.

All capitalized terms that are not otherwise defined herein shall have the same meaning as they are defined in the PJM Open Access Transmission Tariff, Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, or the PJM Manuals.

## Dynamic Transfers Business Rules

1) All Dynamic Transfers are required to comply with applicable NERC Standards [ii], PJM's Open Access Transmission Tariff ("Tariff"), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), PJM's Dynamic Transfer Signal requirements [vii], and applicable PJM Manuals.

2) Several options exist for the Dynamic Transfer of an external unit into PJM. These options are summarized here and described in more detail throughout these business rules:

   a. Dynamic Transfer of the entire output of the unit.
   b. Dynamic Transfer of all output above a threshold value. This option is generally used to satisfy load serving obligations where unit is physically located i.e. Native BA [iii] and transfer remainder of the generation output to the Attaining BA [iii].
   c. Dynamic Transfer of a percentage of the unit's output. This option is generally used to transfer a share of a jointly owned resource from the Native BA to the Attaining BA.

   For Capacity Resources, the Dynamic Transfer MW amount established by the threshold value or percentage must be greater than or equal to the RPM/FRR committed (in Installed Capacity (ICAP) terms) value minus any temporary generator derate/outage information provided via the PJM eDART tool [xvi].

   Dynamically transferred Capacity and Energy Resources must notify PJM of scheduled or unscheduled outages via PJM eDART [xvi], and update unit parameters via PJM Market's systems.

3) The value of the Dynamic Transfer for external units where the entire unit's output is not transferred will be determined as follows:

   a. When the unit is producing an instantaneous MW amount below the threshold value for that unit all energy remains in the Balancing Authority(BA) in which the unit is physically located (Native BA [iii]), and the Dynamic Transfer associated with the unit is zero.
   b. When the unit is producing an instantaneous MW amount above the threshold value, then the difference between the actual output and the threshold value is the amount dynamically transferred into PJM.
   c. For dynamically scheduled resources, this threshold value can be zero or the percentage can be 100% for certain periods of time, indicating that the entire output of the unit is transferred into PJM.

4) Units that utilize a threshold value may be dispatched by PJM in both the Day-Ahead and Real-time Markets. The limits utilized by PJM in determination of the dispatch instructions sent for such units will be those submitted by the participant via the eMKT application.

5) For combined cycle units utilizing a threshold value, one threshold value will be utilized for the facility as a whole, as opposed to a value for the combustion turbine and another for the steam turbine. The output of all parts of the combined cycle unit will be combined into one value in order to compare to the threshold and determine the amount dynamically transferred to PJM.

6) The resource will be responsible for providing telemetry to include the total unit/plant output, the threshold or percentage value, and the calculated dynamically transferred amount to both Native and Attaining BAs. PJM and the Native/Attaining BA will exchange these telemetered values to ensure consistent calculation of the Dynamic Transfer and ACE. PJM will alarm for differences between telemetry received by PJM those received by the Native/Attaining BA. PJM and Native /Attaining BA will secure unit telemetry from an alternate source to be used as a backup should the communications link from the resource become unavailable.

7) The threshold value or percentage for each Dynamic Schedule will be communicated by the resource to both the Native BA and Attaining BA prior to 0000 Hrs on the Operating Day for which it is effective whenever such threshold value changes. The PJM Dispatch will make a log entry indicating any changes in these threshold value or percentage. Such changes in threshold value or percentage shall be deemed temporary and for purposes of energy only. Since Pseudo-Ties are not NERC tagged, changes to the threshold or percentage cannot be made on a short term basis. Any such change may require additional firm transmission service to be obtained and requires further coordination between the impacted BAs.

8) Units that dynamically transfer a percentage of the unit's output may be dispatched by PJM in both the Day-ahead and Real-time Markets. The unit's limits must be submitted to PJM via the eMKT application, and must reflect the percentage of the output scheduled into PJM, not the entire unit capability (e.g., startup costs, ramp rates). NERC Tags shall accordingly be updated for Dynamic Schedules per applicable NERC standards.

9) All Capacity Resources must secure Firm Point-to-Point or Network External Designated Transmission Service [xviii] up to their RPM/FRR commitments (in ICAP terms) and use that secured transmission service to transfer energy into PJM. These resources are required to offer at a minimum the committed installed capacity portion in the PJM Day-Ahead Market. Additionally, all Capacity Resources shall provide a letter of non-recallability [xv].

10) Units that dynamically transfer the entire unit's output (zero threshold value or 100% of unit output) into PJM will be eligible for dispatch by PJM in both the Day-ahead and Real-time markets. Such units are required to submit start-up and no-load

values and are eligible for Operating Reserve credits when committed by PJM and following PJM dispatch instructions.

11) Dynamically transferred resources must coordinate and gain Native and Attaining BA[iii] agreement on:
    a. Primary and redundant Dynamic Transfer Signal (telemetry) used in modeling Pseudo-Tie.
    b. Additional calculations or processing required for the Dynamic Transfer Signal [ii].
    c. Whether the Pseudo-Tie is uni-directional or bi-directional.
    d. Coordinating the use of same value in ACE for loss of Pseudo-Tie transfer telemetry [iii].
    e. Reliability Coordinator (RC) for the pseudo-tied facilities.
    f. Inclusion of Pseudo-Tie in Attaining BA [iii] real-time load calculation and load forecasts. Exclusion of Pseudo-Tie in Native BA real-time load calculation and load forecasts.
    g. Any ramping limitations to avoid large changes to the Native/Attaining BA ACE.
    h. The accounting of losses resulting from the Dynamic Transfer.

12) If a dynamically transferred unit is self-scheduled in the PJM market, the resource must notify the PJM Dispatch at least 20 minutes in advance when the instantaneous MW value of the Dynamic Transfer is to be changed. This advance notice is required so that adequate system control may be maintained.

13) Should a unit from which all or a portion of the output is currently dynamically transferred into PJM trip off-line, the resource shall notify the PJM Dispatch immediately of the value of the Dynamic Transfer at the time of the trip. Additionally, the unit owner or market operating center responsible for a Dynamic Schedule should immediately adjust the NERC tag to reflect the energy loss. The outage shall be communicated via eDART [xvi].

14) Dynamically transferred generation can be used to provide Contingency Reserves[i] (primary reserves) in only one BA [xi] and must acquire Firm Transmission Service. If a TLR event curtails the firm transmission reservations, PJM Dispatch will terminate the assignment and these resources will then no longer be provided financial payments for Synchronized Reserves obligations. NERC Tags shall accordingly be updated for Dynamic Schedules per applicable NERC standards to reflect the Synchronized Reserve service provided. Pseudo-Tied generation can provide Non-Synchronized Reserve since it is considered to be within PJM's metered boundaries [xvii].

15) A dynamically transferred resource could be eligible to provide Regulation services to the PJM market only if the resource is not already providing Regulation services

to another BA. The requirements for resources to qualify and provide regulation services are documented in [xiii][xiv]. In addition, dynamically scheduled resources are recommended to arrange Firm Transmission Service from the Native BA to PJM in order to meet their Regulation service obligations. Further, the resources must be capable of receiving nodal economic dispatch base-points from PJM and the resources should make automatic regulation control signals [viii] available to PJM. If a dynamically scheduled resource is curtailed due to a TLR initiation, the generation owner must communicate its curtailment to PJM.

16) A dynamically transferred resource will only get cleared for one ancillary service at a particular hour (i.e., either Regulation or Synchronized Reserves). Resources that are dynamically transferred via a percentage of the unit's output may be limited in which ancillary service markets they are eligible to participate.

17) After-the-fact, which is typically the next business day, the participant responsible for the unit will submit hourly integrated values of each Dynamic Transfer to the PJM eMeter system to be used in the PJM settlement process. These values will be the hourly integrations of the Dynamic Transfers calculated in real-time, and PJM will verify them against the hourly integrated values of these transfers as calculated in the PJM EMS.

18) The following restrictions apply to non-capacity portion of Dynamic Transfers:

   a. With the exception of a capacity emergency in the unit's Native BA, the threshold value for a given unit or combined cycle plant may not be changed during the Operating Day. A new threshold value for a given unit or combined cycle plant may be submitted prior to 0000 of the Operating Day, but at the time the new threshold value takes effect, the unit must be producing a MW amount that is less than both the old and new threshold values such that the value cannot change instantaneously or ramp to a new value while the unit output does not change accordingly. NERC Energy Emergency Alert Level 2 (EEA Level 2) will be issued by the Balancing Authority's Reliability Coordinator as notification of the capacity emergency.

   b. With the exception of a capacity emergency in the unit's Native BA, the Dynamic Transfer percentage for a given unit or combined cycle plant may not be changed during the Operating Day. A new percentage for a given unit or combined cycle plant may be submitted prior to 0000 of the Operating Day, but at the time the new percentage takes effect, the unit must be offline, such that the value of the Dynamic Transfer does not change instantaneously or ramp to a new value while the unit output does not change accordingly. NERC EEA 2 will be issued by the Balancing Authority's Reliability Coordinator as notification of the capacity emergency.

c. In anticipation of an immediate capacity emergency in the unit's Native BA, the Native BA may request values of the non-capacity backed portion of Dynamic Transfers to zero. The Native BA will request this action only when the Native BA has declared NERC EEA Level 2, indicating that a capacity emergency situation is imminent to the point that emergency procedures are foreseen or have been implemented up to but not including curtailments of firm load commitments. The Balancing Authority will provide as much notice as possible to the PJM Dispatch when this action becomes necessary, and PJM Dispatch will make every effort to accommodate this request as expeditiously as possible.

d. Capacity backed Dynamic Transfers cannot be reduced by the Native BA. Instead, the Native BA can request to make an emergency energy purchase after it has declared an NERC EEA Level 2.

e. Non-capacity generating units may be dynamically scheduled into PJM utilizing either Firm or Non-Firm Transmission Service on system(s) external to PJM. However, should curtailment of a Dynamic Schedule due to the Non-Firm nature of the Transmission Service utilized on systems external to PJM cause real-time operational difficulties, PJM may suspend the ability for the generator to be dynamically schedule into PJM until such time as Firm transmission service on the external system(s) is procured to minimize the probability of future curtailments.

19) LMP and Base Point Requirements must be satisfied as follows:

a. A Pseudo-Tie must receive a unit level basepoint and nodal LMP.
b. If a resource using a Dynamic Schedule wishes to receive a unit level basepoint and nodal LMP, the resource must provide the necessary input data to update the PJM EMS model, which is required for PJM Security Constrained Economic Dispatch (SCED) and Locational Pricing Calculator (LPC) tools. Specifically, the resource must provide adequate modeling information to ensure an accurate EMS State Estimation, Marginal Loss Calculation, and Shift Factor calculations.
c. If a self-scheduled resource using a Dynamic Schedule wishes to receive an existing external interface LMP to follow PJM dispatch, PJM can provide the interface LMP via ICCP. However, the resource must provide 20 minutes notice prior to adjusting MW output.
d. If PJM determines that a new interface LMP is required to support the Dynamic Schedule, PJM will work with the resource owner to create a new interface LMP pursuant to section 2.6A of Attachment K-Appendix of the PJM Tariff and Schedule 1 of the Operating Agreement.

20) If the owner /operator of a dynamically transferred unit is exporting energy from PJM at the same time any of that entity's units are dynamically transferring energy into

PJM, and the energy being exported is flowing across the same PJM Interface as the dynamically transferred import would flow were it not dynamically transferred, then the energy being exported (up to the amount being dynamically transferred into PJM) will be priced at the higher of the dynamically transferred unit's bus price or the interface where the energy is being purchased. Any remaining energy being exported from PJM by this participant will be priced at the appropriate export interface.

21) For intermittent generation such as wind units additional information as listed in Manual 14D [xii] shall be made available to PJM for developing a forecast.

22) Termination of Dynamic Transfers must be coordinated between Native/Attaining BA and the resource.

### PJM EMS Modeling Requirements for Implementing Pseudo-Ties:

PJM Manual 3A [x], summarizes the PJM Model process and PJM and member obligations to create and maintain an accurate model of the electric system. An accurate model is required to analyze real-time conditions to help ensure that PJM and the neighboring transmission systems are operated safely and reliably. The PJM EMS model is used to support Real-time Security (Model Update, State Estimation, Security Analysis, Transient Stability and Transfer Limit Calculations (Interconnection Reliability Operating Limit (IROL) determination)), and study-mode simulations for short-term operations analysis (primary outage planning), as well as, Day-ahead Markets, Real-time LMP, Security Constrained Economic Dispatch calculations and FTR auctions.

PJM staff is responsible for regularly exchanging and updating models to support Joint Operating Agreements (JOAs) with neighboring systems. While external generation may not have a significant impact on PJM Transmission Facilities, their output can impact local or neighboring BA transmission facilities, which may be subject to "market-to-market" congestion management. It is for this reason that PJM is required to adequately expand our external model to support market-to-market calculations while ensuring continued State Estimator stability under normal and outage conditions.

For instance, The PJM-MISO Joint Operating Agreement Section 4.1 Market Flow Determination, specifically states that "[u]nits assigned to serve a market area's load do not need to reside within the market area's footprint to be considered in the Market Flow calculation. Units outside of the market area that are Pseudo-Tied into the market to serve the market area's load will be considered in the Market Flow calculation". If a Pseudo-Tie wishes to participate in the PJM Market per the PJM/MISO JOA Section 4.1, PJM is obligated to calculate a generation to load Market Flow for all PJM market-to-market and nonmarket-to-market flowgates. This means that according to current

PJM/MISO JOA agreement, PJM will have to model the Pseudo-Tie generator in PJM's EMS such that the Generation to Load market flow can be calculated, and therefore a Pseudo-Tied resource will require nodal representation, not an interface mapping representation.

PJM limits EMS model builds to four times per year in order to ensure a "stable" model for all stakeholder/participants. The Summer and Winter build typically focus on modeling grid modifications resulting from the near-term, future transmission and generation construction project reported by Transmission and Generation Owners throughout the PJM footprint. The Spring and Fall builds are focused on updating or expanding the external system model as required but also serve as additional opportunities to correct known modeling problems with PJM Generation and Transmission Owner facilities. In the effort to ensure model quality and dependable and accurate solutions prior to placing a new model into production, EMS support staff completes a rigorous 'soak' test by testing SCADA data directly to the new model to ensure that the models produce a stable solution consistent with the results of the previous model. It is for this reason that incorporation of new Pseudo-Ties into the PJM model typically requires 6 – 12 months lead time depending on the location of the external resource and level of existing modeling, but can require additional lead time depending on its electrical proximity to the existing PJM RTO footprint. In contrast, a Dynamic schedule may take 1-4 months lead time depending on the services offered by the resources and modeling required.

PJM staff will evaluate the feasibility of upgrading the PJM EMS model to explicitly model the Dynamic Transfer resource. If determined to be feasible, the cost of the model upgrade will be borne by the external resource requesting Dynamic Transfer capability.

The above mentioned business rules and modeling requirements are summarized in Appendix C.

## References


[i] Glossary of Terms Used in NERC Reliability Standards (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf)

[ii] NERC Standard BAL-005-0.2b, R10, R12.3: (http://www.nerc.com/files/BAL-005-0_2b.pdf)

[iii] NERC Operating Manual , NERC Dynamic Transfer Reference Guidelines: (http://www.nerc.com/files/opman_3_2012.pdf)

[iv] NERC Standard INT-001-3, R1: http://www.nerc.com/files/INT-001-3.pdf

[v] NERC Standard INT-004-2,R2 (http://www.nerc.com/files/INT-004-2.pdf)

[vi] NERC Standard BAL-003-0.1b- Frequency Response and Bias,R4: (http://www.nerc.com/files/BAL-003-0_1b.pdf)

[vii] PJM Manual 1- Control Center and Data Exchange Requirements, Section 5.3.5: (http://www.pjm.com/~/media/documents/manuals/m01.ashx)

[viii] PJM Manual 14D- Generator Operational Requirements, Section 4.1.4: (http://www.pjm.com/~/media/documents/manuals/m14d.ashx)

[ix] PJM Regional Transmission and Energy Scheduling Practices document, section 1.2.12: (http://pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx)

[x] PJM Manual 3A- Energy Management System Model Updates and Quality Assurance (http://www.pjm.com/~/media/documents/manuals/m03a.ashx)

[xi] NERC Standard BAL-002-1- Disturbance Control Performance, R2.6 (http://www.nerc.com/files/bal-002-1.pdf)

[xii] PJM Manual 14D- Generator Operational Requirements, Section 8: (http://www.pjm.com/~/media/documents/manuals/m14d.ashx)

[xiii] PJM Manual 11- Energy & Ancillary Services Market Operations, Section 3: (http://www.pjm.com/~/media/documents/manuals/m11.ashx)

[xiv] PJM Manual 12- Balancing Operations, Sections 4.4,4.5: (http://www.pjm.com/~/media/documents/manuals/m12.ashx)

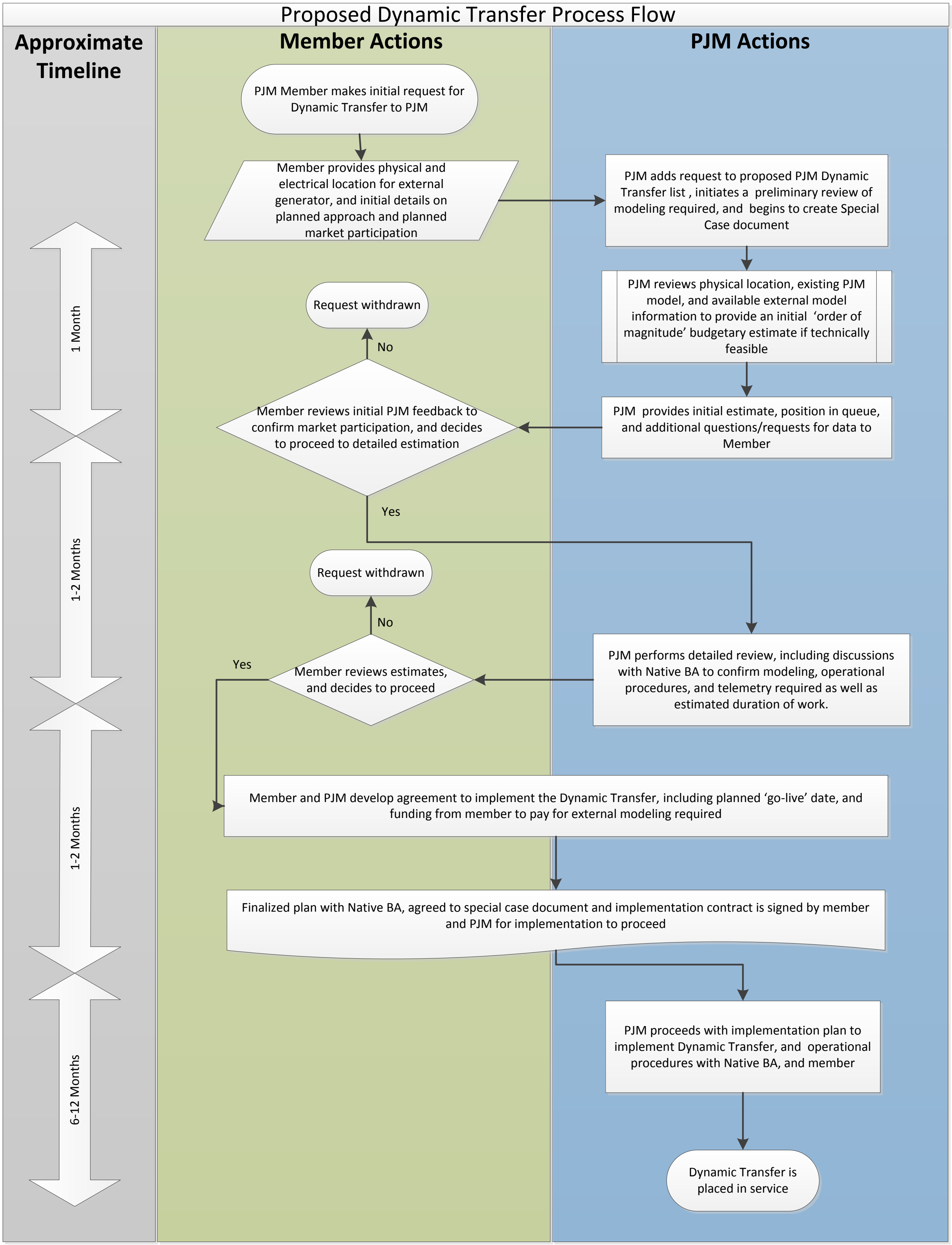
[xv] PJM Manual 18- PJM Capacity Market, Sections 4.2.4: (http://www.pjm.com/~/media/documents/manuals/m18.ashx)

[xvi] PJM Manual 10- Pre-Scheduling Operations, Sections 2: (http://www.pjm.com/~/media/documents/manuals/m10.ashx)

[xvii] Operating Agreement of PJM Interconnection, L.L.C., Section 1.7.19A.01: (http://www.pjm.com/~/media/documents/agreements/oa.ashx)

[xviii] PJM Manual 18- PJM Capacity Market, Sections 4.2.2: (http://www.pjm.com/~/media/documents/manuals/m18.ashx)

## Appendix A: Dynamic Transfer Process Flow



## Appendix B: Dynamic Transfer Documentation Template

### *Special Cases Document for Generator XXXXX*

| | |
|---|---|
| Current <Name of TO> Operation | "Special Case" because:<br><br>Generator or Load?<br><br>How is this currently scheduled?<br><br>What data is submitted, what parties are involved and how is it transferred?<br><br>How are losses handled currently?<br><br>How are ancillaries handled?<br><br>What is the current checkout approach?<br><br>Who is the marketer (LSE / Gen Owner)?<br><br>How is this currently modeled in <Name of T0> EMS?<br><br>Is there any behind-the-meter generation?<br><br>If applicable, is net or gross metering used?<br><br>Other Notes: |
| <Name of TO> Integration Approach | How will this be scheduled?<br><br>What data will be submitted, what parties will be involved and how will it be transferred?<br><br>How will losses be handled?<br><br>How will ancillaries be handled?<br><br>What will be the checkout approach?<br><br>Who will be the marketer (LSE / Gen Owner)?<br><br>How will this be modeled in PJM's EMS?<br><br>If it exists, will behind-the-meter generation need to be modeled?<br><br>If applicable, will net or gross metering be used?<br><br>Other Notes: |

| | |
|---|---|
| **Parties Involved for Integration (Roles and Membership Status)** | |

## *Transmission Service*

| | |
|---|---|
| **Owner of Service** | |
| **Path (POR/POD)** | |
| **Source** | |
| **Sink** | |
| **MW** | |
| **Start Date** | |
| **Stop Date** | |
| **FTRs (Firm Only)** | |
| **Product Type (Firm, Network, Grandfathered)** | |

## *Tag**

| CA | TP | POR | POD | SE | Token | Value |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

**Dynamic Schedules require an EES tagging special exception which will be made available for the sole use of the requesting entity in flagging the dynamic NERC Tag as a special case in PJM's scheduling system. This exception must be attached to the tag by placing it in the "miscellaneous" column on the PJM Transmission Provider line of the "physical path" portion of the tag.*

***A Dynamically Scheduled resource will require to input a NERC tag for PJM eMFC tool to account for the unit injection to PJM in its Market Flow calculations. The POR_NAME should be PJMSYSGEN.*

## *Scheduling*

| | |
|---|---|
| **General Assumptions** | |

| | |
|---|---|
| Schedule | |
| Loss Schedule | |

### *Energy Market Overview*

| | |
|---|---|
| Market Approach | |
| Day Ahead Procedure | |
| Real-time Procedure | |

### *Billing and Settlements*

| | |
|---|---|
| General Assumptions | |
| Related Agreements that Apply | |
| Inadvertent | |
| Network Losses | |
| eSchedule Account Set-up and procedure | |
| eMTR Account Set-up and procedure | |
| Spot Market | |
| Congestion | |
| Point-to-Point Losses | |
| Regulation | |
| Spinning Market | |
| Condensing [Future Reactive] | |
| Operating Reserves | |
| Capacity Credit Market and Deficiency | |

| | |
|---|---|
| **FTRs/FTR Auction** | |
| **Meter Correction** | |
| **Schedule 9-1** | |
| **Schedule 9-2** | |
| **Schedule 9-3** | |
| **Schedule 9-4** | |
| **Schedule 9-5** | |
| **Schedule 9-FERC** | |
| **Schedule 1A** | |
| **Reactive (Schedule 2)** | |
| | **Reactive Revenue Requirements:**<br>• **Will they be filed?**<br>• **Who will be responsible for filing?**<br>• **Who will get paid?** |
| **Black Start (Schedule 6A)** | |
| **Network Service** | |
| **Point-to-Point Service** | |

## *Required Documentation*

| | |
|---|---|
| **PJM Operating Agreement** | **Required?** |
| **Certificate of Designated Agency** | **Required?**<br>**Has signoff taken place?** |

## *Contact Information*

| Name | Company | Role (i.e. Owning, Operating, Marketing, Counterparty) | E-Mail Address | Phone/Fax Number |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| | | | | |
| | | | | |
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## *Outstanding Issues/Action Items and Responsible Party*

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|---|---|
| | |
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| | |
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| | |
| | |

## *Additional Notes/Pictures:*

## Appendix C: Dynamic Transfer Requirements Summary

| Market Service | Requirement | Pseudo-Tie | | | Dynamic Schedule | | |
|---|---|---|---|---|---|---|---|
| | | Entirely | Threshold | Percent | Entirely | Threshold | Percent |
| **Capacity** | Transmission Service | Firm/NED >= RPM Committed ICAP | Firm/NED >= RPM Committed ICAP | Firm/NED >= RPM Committed ICAP | Firm/NED >= RPM Committed ICAP | Firm/NED >= RPM Committed ICAP | Firm/NED >= RPM Committed ICAP |
| | NERC Tagging | None | None | None | Required | Required | Required |
| | Letter of Non Recallability | Required | Required | Required | Required | Required | Required |
| | Day Ahead | Must Offer >= RPM ICAP | Must Offer >= RPM ICAP | Must Offer >= RPM ICAP | Must Offer >= RPM ICAP | Must Offer >= RPM ICAP | Must Offer >= RPM ICAP |
| | Outage Reporting (eDART) | Required | Required | Required | Required | Required | Required |
| **Energy** | Transmission Service | Firm | Firm | Firm | Firm/Non-Firm | Firm/Non-Firm | Firm/Non-Firm |
| | NERC Tagging | None | None | None | Required | Required | Required |
| | Outage Reporting (eDART) | Required | Required | Required | Required | Required | Required |
| | Nodal Representation-EMS, LMP | Yes | Yes | Yes | Not required for Interface Pricing | Not required for Interface Pricing | Not required for Interface Pricing |
| | Unit Basepoint | Yes | Yes | Yes | Not required for Interface Pricing | Not required for Interface Pricing | Not required for Interface Pricing |
| | Self-Scheduled Gen | 20 min notice | 20 min notice | 20 min notice | 20 min notice | 20 min notice | 20 min notice |
| | Operating Reserve Credit | Eligible | Eligible if Threshold zero | Eligible if 100% | Eligible | Eligible if Threshold zero | Eligible if 100% |

| Market Service | Requirement | Pseudo-Tie | | | Dynamic Schedule | | |
|---|---|---|---|---|---|---|---|
| | | Entirely | Threshold | Percent | Entirely | Threshold | Percent |
| **Ancillary Services-Regulation/ Contingency Reserves** | Transmission Service | Firm | Firm | | Firm/Non-Firm | Firm/Non-Firm | |
| | NERC Tagging | None | None | | Required | Required | |
| | Outage Reporting | Notify PJM Dispatch asap | Notify PJM Dispatch asap | | Notify PJM Dispatch asap | Notify PJM Dispatch asap | |
| | Nodal Representation-EMS | Yes | Yes | | Yes | Yes | |
| | Qualification and Scoring Process | Similar to PJM internal resources | Similar to PJM internal resources | | Similar to PJM internal resources | Similar to PJM internal resources | |
| **Other Requirements** | eMeter Checkout | Yes | Yes | Yes | Yes | Yes | Yes |
| | Redundant Path Telemetry | Yes | Yes | Yes | Yes | Yes | Yes |
| | Time Frame for Implementation | 6-12 Months | | | 1-4 Months | | |
| | Cost of Implementation | Borne by Resource Owner | | | Varies based on services provided | | |