Freeze Date Straw Proposal Draft

5/18/2017

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1.0 Introduction

The purpose of this document is to describe the proposed solution for updating various components of Firm Flow Limits (FFLs) and Firm Flow Entitlements (FFEs) utilized in the Congestion Management Process (CMP) and Joint Operating Agreements (JOA), respectively. FFLs and FFEs, commonly referred to as allocations, are assigned to each entity for each Reciprocally Coordinated Flowgate (RCF). These allocations are critical inputs into the FFE and FFL values used in the Market-to-Market (M2M) and Available Flowgate Capacity (AFC)/Available Shared of Total Flowgate Capacity (ASTFC) processes that exist today. The CMP was created by entities that now make up the Congestion Management Process Working Group (CMPWG). The CMP members currently include PJM, MISO, SPP, TVA, Manitoba Hydro, Minnkota Power Cooperative, AECI, and LGEE/KU. Further, MISO and PJM as well as MISO and SPP each have JOAs that are in addition to the CMP agreement. This document provides a summary of the solution, design components, background information and timetable for implementation. Some of the solutions and design components may not be valid or may be different between market and non-market entities. Market Entities include PJM, MISO and SPP, while non-market entities include TVA, Manitoba Hydro, Minnkota Power Cooperative, AECI, and LGEE/KU.

2.0 Executive Summary

The market-to-market congestion management process for market entities utilizes FFEs for an after-the-fact settlement calculation whenever the M2M process is used to manage congestion on a reciprocally coordinated flowgate. The FFE calculation that is currently used dates back to 2004 (Freeze Date) and was designed to preserve the historic firm rights of the transmission system prior to the formation of organized markets. Since that time, changes have occurred to the way in which the RTOs operate and plan their respective systems. The purpose for updating the FFE calculation is to reflect these changes while still maintaining the original intent to preserve the historic usage of the transmission system. There are also differences in how the entities operate and plan their systems, so updating the FFE calculations must ensure no entity would be unfairly benefited or harmed due to a difference in an internal practice.

The Transmission Loading Relief (TLR) congestion management process is a NERC standard used by both non-market entities and market based entities alike. This process utilizes FFLs for market based entities to establish firm (FN7) and non-firm (6-NN, 2-NH) Market Flows that will be used during a TLR event. Market Flows are defined as the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving market load within a Market-Based Operating Entity's market.

3.0 Existing Process Background

Calculation of historic firm rights between CMP entities utilizes a snapshot of generators and Transmission Service Reservations (TSRs) that existed in 2004 (prior to most major market integrations) along with the most recent topology (IDC PSSE model), load and outage forecasts, and any generation retirements. In this calculation, the Balancing Authorities (BAs) that existed on the Eastern Interconnection at this time (2004) are preserved. These BAs are re-designated as Local Balancing

Authorities (LBAs) within the current BAs with which they have integrated. For each LBA, directional generation-to-load (based on established generator priorities) and point-to-point impacts on a dynamic set of regional flowgates are calculated for a number of forward looking horizons, each with different load and outage forecasts. This process is specifically defined in Section 6 of the CMP.

The diagram below from Section 6.4 of the CMP illustrates the general concept:

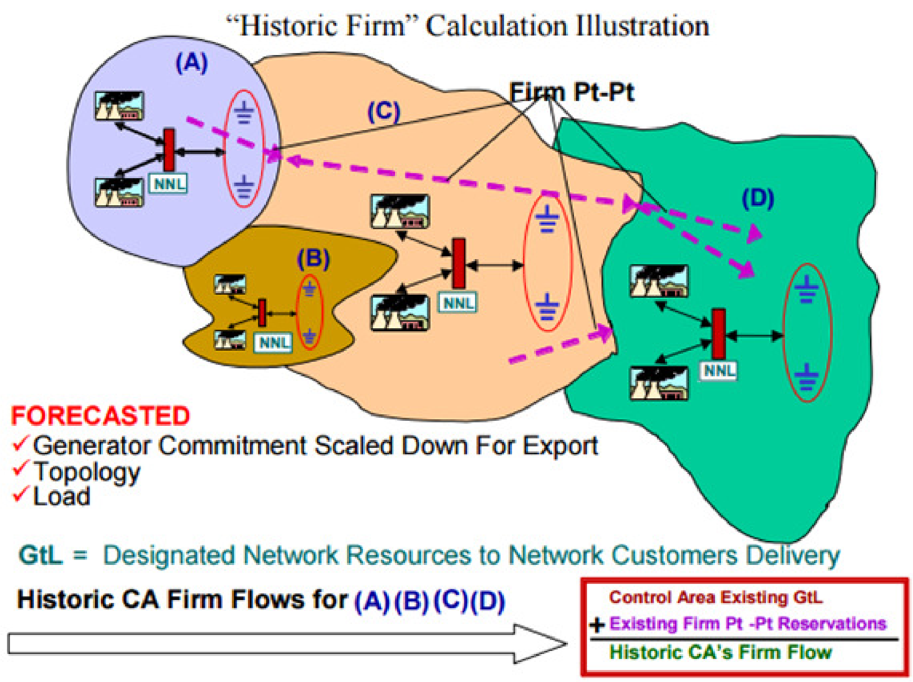

Figure 1 - Historic Firm Calculation

These impacts are aggregated on a flowgate and BA basis and downloaded by each CMP entity, who then use an agreed upon universal set of rules to allocate these historic impacts into historic allocations on a BA basis.

The forward horizons calculated consist of the following, and a higher of logic is used in an attempt to protect entities from undue harm due to outages and other factors:

Allocation Run Type	Allocation Process Start	Range Allocated	Allocation Process Complete
April Seasonal Firm	Every April 1 at 8:00 EST	Twelve monthly values from October 1 of the current year through September 30 of the next year	April 1 at 12:00 EST
October Seasonal Firm	Every October 1 at 8:00 EST	Twelve monthly values from April 1 of next year through March 31 of the following year	October 1 at 12:00 EST
Monthly Firm	Every month on the second day of the month at 8:00 EST	Six monthly values for the next six successive months	2nd of the month at 12:00 EST
Weekly Firm	Every Monday at 8:00 EST	Seven daily values for the next Monday through Sunday	Monday at 12:00 EST
Two-Day Ahead Firm	Every Day at 17:00 EST	One daily value for the day after tomorrow	Current Day at 18:00 EST
Day Ahead Non-Firm	Every Day at 8:00 EST	Twenty-four hourly values for the next 24-hour period (Next Day HE1-HE24 EST)	Current Day at 9:00 EST

Table 1 – Forward Calculation Schedule

These allocations are used in CMP entities Available Flowgate Capacity (AFC) and Available Transfer Capability (ATC) calculations for utilization of transmission service sales for the same horizons. They are also used to directly establish firm flow limits for non-firm and firm flow curtailment under TLR and are an input to the FFE calculation. A calculation flow diagram is shown below.

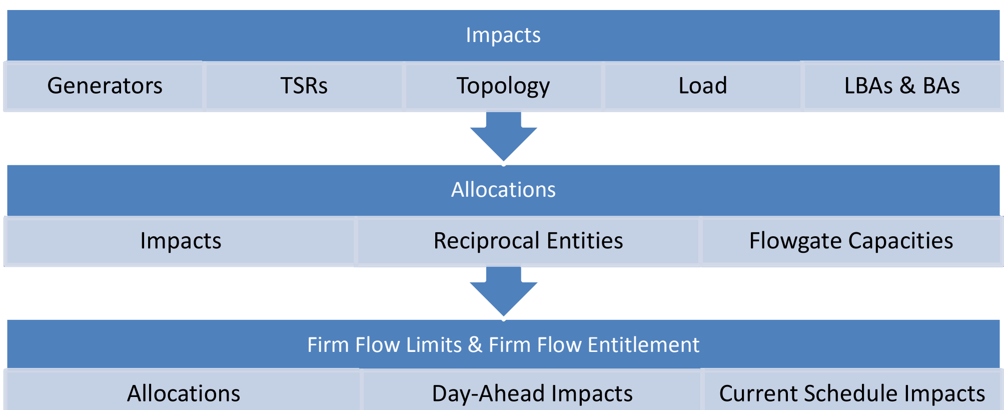

Figure 2: Firm Flow Entitlement Calculation

4.0 Design Components

There are many different aspects of the FFE calculation, which have been broken down into design components. Included for each design component is a general description, the current practice that is used and the proposed solution under consideration with the CMPWG. The following table provides a summary of the design components and the collaborated solutions.

Design Component	Section References	Status Quo	Proposed Solution
Granularity	4.1.0	LBA	LBA for Buckets 1, 2, 3 and RTO for Bucket 4
NRs/DNRs	4.2.0	Priority - Prior to 4/1/2004 Priority Zero – Post 4/1/2004	Bucket 1 - pre-2004 DNR/NRs Bucket 2 - post-2004 DNR/NRs Bucket 3 & 4 - All DNR/NRs are eligible
TSRs	4.3.0	6/1/2004 to 5/31/2005	Bucket 1 – all active freeze date TSRs with rollover rights and non-active intra BA freeze date TSRs with rollover rights Bucket 2 – all active inter BA post freeze date TSRs with rollover rights, freeze date TSRs not served in Bucket 1 will be served in Bucket 2 Bucket 3 – none Bucket 4 TSR incremental: all active TSRs RTO incremental: Active inter BA TSRs with rollover rights
Transfers	4.4.0	None	Bucket 1 & 2 – no transfers Bucket 3 – LBA Reliability Transfers, limited transfers for short LBA (Pro-rata from long to short LBAs), subject to contractual arrangements and reliability limits Bucket 4 – market based transfers align with planning processes 1. TSR Incremental 2. RTO Incremental

Design Component	Section References	Status Quo	Proposed Solution
Impact Methodology	4.5.0	Impacts are generated by first historic TSRs and then LBA based GTL using priority resources (freeze date) first and priority zero (post freeze date) resources second	Bucket 1 – Active Freeze Date Inter-BA TSR impacts calculated first (ER and NR), Freeze Date Intra-BA TSR impacts second, LBA GTL third using freeze date DNR/NRs Bucket 2 – Inter-BA TSR impacts calculated first, LBA GTL second using post freeze date DNR/NRs, unserved Freeze Date Intra-BA TSR impacts third Bucket 3 – Reliability Transfers between long and short LBAs after bucket 2 Bucket 4 – TSR/RTO Incremental approach that aligns with current operational and planning constructs
Allocation Methodology	4.6.0	Thresholds are applied 0% and 5%, rules apply for CBM, excess determined on historic ratio	To be determined
Excess Capacity	4.7.0	Socialized based on historic ration	Owner
Addressing Parallel Flows through Planning	4.8.0	Coordination between entities embodied in JOAs, the CMP, and business practice manuals	Commitments to pursue enhancements where applicable
Capping FFE/FFL	4.9.0	No	Capped for FFE, to be determined for FFL pending discussion
Run Types	4.10.0	Seasonal, Monthly, Weekly, Two Day Ahead, Daily	Status Quo
Merit Order	4.11.0	LBA based priorities	Priority determined on a BA basis and applied in same sequential order on a LBA basis
Topology	4.10.0~~4.12.0~~	Current System Topology	Out of scope
Incremental Upgrades	4.10.0~~4.12.0~~	TUS + Appendix G DNRs	Out of scope
Pseudo-Ties	4.10.0~~4.12.0~~	Handled on a case by case basis	Out of scope
TLR & FFL	TBD	Forward non-threshold (<5%) allocation establish the Firm Flow Limit (FFL) for Market Based Entities	To be determined

Comment [JSR1]: Reviewing

Comment [JSR2]: Reviewing

Comment [RA3]: Reviewing

Design Component	Section References	Status Quo	Proposed Solution
Higher of Logic	TBD	Yes	To be determined
Directional Allocation/ Net Allocation	TBD	Directional Allocation	To be determined
Update Frequency	TBD	Freeze Date	To be determined
ASTFC Processes	TBD	ASTFC analysis to evaluate firm transmission services	To be determined

Table 2: Design Component Summary

4.1.0 *Granularity*

Description: Granularity refers to the area of load that is served for the purposes of calculating of impacts on each flowgate. This component is important because the referenced area will determine the shift factors used in the impact calculation. It also determines the generator groupings and merit order used in serving load. Local Balancing Authority (LBA) level granularity results in impacts calculated from generation to load served within an LBA. Regional Transmission Organization (RTO) or BA level granularity results in impacts calculated from generation to the aggregated RTO or BA load. In order to preserve historic usage of the transmission system, the granularity at the LBA level is used to be consistent with pre-2004 Freeze Date timeframe (with exceptions agreed to by the CMPWG).

Current Practice: Granularity is currently to the historic LBA level.

Proposed Solution: The proposed solution will allow for preserving the historic usage of the system while enhancing the calculation to accommodate updated dispatch and planning processes, if applicable. The solution involves a bucket approach to allocating impacts. The buckets will be separated by priority as demonstrated in Table 3 below. Buckets one and two will preserve the historic usage by using the LBA granularity. Bucket three granularity is defined on an LBA basis for purposes of transferring powers between LBAs to ensure all load is served in the impact calculation. Bucket four will accommodate the entities that dispatch and plan their systems on a BA/RTO basis by allocating transfer impacts between LBAs, limited by (the lower of reliability limits or contractual arrangements) if available. These transfers will originate from one of the three proposed transfer impact calculation methodologies outlined in 0~~4.4.0~~ and 4.5.0. These transfer methodologies are intended to resemble the different planning study approaches that are currently being employed amongst CMP parties.

	Allocation Priority	Granularity
Bucket 1	1	LBA
Bucket 2	2	LBA
Bucket 3	3	LBA
Bucket 4	4	BA/RTO

Table 3: Bucket Approach to Allocations

4.2.0 *Network Resource*

Comment [JSR4]: The group is working to fully establish and define what a Network Resource (or Designated Network Resource) is.

Description: A list of eligible generators to serve each BA or LBA load is cornerstone to the impact calculation. It is important that this list of generators be only resources that an entity can reliably depend upon to serve its network load. Generators fitting this description are determined differently by each CMP entity based on their interconnection, planning, and capacity requirements. Generators meeting those requirements either have the ability to be or have been designated to serve network load, labelling the generator a Network Resource (NR). In addition, each set of NRs needs to be assigned a merit order list to be used the allocation calculation. This merit order is necessary because total generation is only assigned up to the load value of the LBA. Generation in excess of load may not be utilized in the allocation calculation. Generators that do not meet the designation requirements of the BA or CMP entity to which they belong are referred to as “energy only” resources. NRs that had non-zero priority in the freeze date construct are called Designated Network Resources (DNRs). These generators were a NR prior to the Freeze Date (5/1/2004), while generators that came in service after this date are NRs and/or DNRs. The only functional difference between a DNR and NR is that a DNR is designated by load.

Current Practice: Currently, NRs that were in in service prior to the Freeze date (2004) receive an ordered priority in which they are dispatched to serve load. If any remaining load exists after dispatching these DNRs, generators (energy only and NRs alike) that came into service after the Freeze date are dispatched slice of system (pro-rata) to meet any remaining LBA load. Any load remaining after all generation within the LBA has been dispatched goes unserved.

Proposed Solution: The proposed solution requires that generators that are eligible to be included in the entitlement calculation have the ability to be or are designated by an entity to serve its load. All CMP entities agree to provide notification of any changes to processes associated with DNR/NR eligibility.[1] In order to preserve existing priorities of historic generation, pre-Freeze Date DNRs are assigned on an LBA basis in bucket one, post-Freeze Date NRs are assigned on an LBA basis in bucket two. Network Resources can have both Freeze Date DNR MWs and Post Freeze Date NR MWs at the same time, to the extent that only a portion of the current Pmax of the Network Resource was a DNR under the freeze date. The specific mechanics regarding the application of DNRs and NRs are detailed in Section 4.5.0.

Bucket	Description	Allocation Priority	Granularity
1	Freeze Date DNRs/NRs	1	LBA
2	Post Freeze Date NRs	2	LBA

Table 4: DNR Classifications

4.3.0 *Transmission Service Reservations (TSRs)*

Description: Transmission Service Reservations (TSRs) are reservations that provide a customer with firm transmission rights on the system. TSRs are included in the allocation calculation as historic rights to the transmission system. These rights are studied through an entities planning process for feasibility similar to DNRs.

The different classes of Transmission Service Reservations (TSR) are as follows:

- Freeze Date TSRs - Firm Point-to-Point (PTP) TSRs that existed prior Freeze Date.
- Post Freeze Date PTP TSRs - Long Term Firm Point-to-Point TSRs with Roll-over rights that exist today.
- Network Integrated Transmission Service (NITS) TSRs – TSRs that are used to explicitly designate generation for the purposes of serving load.

The table below provides a more detailed summary.

TSR	Level	Granularity	Bucket	TDF Calculation
Active Freeze Date TSRs	Inter BA	LBA	1	GTL
All Freeze Date TSRs	Intra BA	LBA	1	GTL
All active Post Freeze Date TSRs	Inter BA	LBA	2	GTL
All active Post Freeze Date TSRs	Intra BA	RTO/BA	4	GTL
All active Post Freeze Date TSRs	Inter BA	RTO/BA	4	GTL

Table 5 - Transmission Service Reservation (TSR) Categories

PJM

Before market integration, PJMs LBAs sold transmission service separately, and maintained their own OASIS systems individually (ComEd, AEP, etc.). Currently, PJM sells transmission service with service points either sourcing or sinking into the RTO. For this reason, PJM Freeze Date TSRs have source and sink points that are not compatible with current transmission service sold into or out of PJM.

Generation-to-Load Methodology (GTL)

TSRs that represent firm transmission capability will utilize a Generation-to-Load (GTL) TDF calculation which is derived by taking the aggregate source Weighted Generator Shift Factor (WGSF) and subtracting the aggregate sink Weighted Load Shift Factor (WLSF). The impact on a flowgate is then this TDF multiplied by the MW amount of the TSR.

Current Practice:

Freeze Date TSRs: Currently, the historic allocation process calculates point to point impacts associated with a static list of TSRs that existed in OASIS systems as of 4/1/2004 for the reference year between 6/1/2004 to 5/31/2005. Each TSR has an LBA designated as a source and sink, and a specified number of megawatts transferred between these two LBAs. This process uses a generation to generation impact calculation methodology.

Post Freeze Date TSRs: Post Freeze Date TSRs are not included or applied in the current allocations calculation.

Proposed Solution:

Comment [NP5]: CMP needs to discuss how Pseudo-Ties fit into the TSR discussion.

Freeze Date TSRs will be included in Bucket 1 to the extent a Freeze Date resource is available to source the reservation. All impacts will be calculated on a GTL basis. Only active inter BA Freeze Date TSRs will be included in bucket 1. It is necessary to include non-active intra BA TSRs in bucket 1 because market entities need a mechanism to represent TSRs that were converted to network service with market integrations. These non-active TSRs will ensure entitlements for flows that are no longer supported by a TSR but through network service.

Post Freeze Date PTP TSRs include only active long term firm TSRs. Active Inter BA Post Freeze Date PTP TSRs will only be applied in bucket 2. Intra BA Post Freeze Date PTP TSRs will be applied in bucket 4 (Transfers). PJM, by evaluating and approving transmission service at the RTO granularity, will apply their TSR impacts on an RTO granularity.

Network Integrated Transmission Service TSRs will be included as a bucket 4 (Transfers) option. Some entities plan their system using explicit TSRs that designate LBA generation or specific clusters of generators to serve LBA load or specific clusters of load.

If a TSR source represents a retired unit or complete set of retired units, that TSR is considered retired and excluded from the impact calculations. To the extent an inter BA TSR exists in both the list of freeze date TSRs as well as current OASIS systems, the TSR will be counted only once, and at the highest priority level (bucket 1). The mechanics of the impact calculation for all TSRs are described in detail in Section 4.5.0.

4.4.0 *Transfers*

Description: This design component refers to allocating any impacts received from generation serving load not located in its native LBA and not represented by a Freeze Date TSR but within the same BA. The original allocation calculation only allocates impacts for generation serving load within its native LBA. Allocations granted from serving load in a different LBA are considered transfers. Today RTOs operate and plan their systems on an RTO granularity, meaning that transfers are occurring in real-time operations. In addition, all RTOs plan to address local reliability and congestion issues; as well as, regional, economic, policy and reliability issues. The proposed solution intends to introduce these constructs into the allocation process.

Current Practice: There is currently no method to receive allocations for transfers.

Proposed Solution: The proposed rules to allow Transfers is a multi-faceted approach; which includes LBA based Reliability Transfers and BA/RTO based Transfers. Reliability Transfers occur after Step X in Section 4.5.0 and consist of LBAs with excessive generation serving LBAs with deficient generation (unserved load).

All CMP entities have the choice to choose an impact calculation that either aligns with a deliverability based planning approach or aligns with a TSR based planning approach. These impacts will be applied in bucket 4. Entities will choose the method that appropriately aligns with their planning construct(s).

All Transfers will be limited by contractual agreements and/or reliability limits. Transfer Impacts will never be negative.

Comment [NP6]: Further discussion required regarding what falls under the category of contractual agreement

Comment [NP7]: Need to discuss the meaning of reliability limits

1. **Bucket 3 (LBA Reliability Transfers)**

   RTO level reliability transfers are transfers associated with an LBA not having enough DNRs plus TSRs to meet its load obligation. This transfer will result in the long LBA transferring MWs to the short LBA on a pro-rata basis, up to the remaining BA load. This provides an incremental impact.

2. **Bucket 4 (BA/RTO based Transfers)**

   a. **TSR Incremental**

BAs that use TSRs to explicitly designate units to serve LBA load can use a similar methodology to calculate total impacts on a flowgate. These impacts are subtracted from the impacts in buckets 1, 2 and 3 to obtain an incremental impact.

b. RTO Incremental

RTO level Transfers use a BA (RTO) level Generation-To-Load impact granularity to allocate RTO impacts. Both Bucket 1 and Bucket 2 generators will be dispatched simultaneously to meet RTO load. These impacts are subtracted from the impacts in buckets 1, 2 and 3 to obtain an incremental impact.

The mechanics for the impact calculation for Transfers is described in Section 4.5.0.

Due to the nature of the CMP entities planning processes being at the BA/RTO level, there is agreement to phase out bucket 3 impacts as well as phase in bucket 4 impacts over a 10 year period. The mechanics for the phase out approach is described in Section 4.6.0.

4.5.0 *Impact Calculation Methodology*

Description: In this agreement, CMP entities recognized that this process needed to respect the historic usage of the transmission system while simultaneously respecting the current policy, planning, markets, and operational constructs that have developed and will continue to develop new investments in transmission.

Current Practice: At a high level, impacts are currently being calculated using the following steps:

For each LBA

1. Freeze Date TSR impacts are calculated using a Generation-to-Generation (GTG) impact calculation (PTP Impact = TDF *MW)
2. All applicable TSR MWs are netted (Net MW = Source MW – Sink MW)
3. If Net MW is less than 0 load is decremented by Net MW (Adjusted Load = Load – Net MW)
4. DNRs are dispatched up to the adjusted load, GTL Impacts are calculated
5. Unserved load is served slice of system by priority zero generators (mix of NRs, energy only resources). Any load remaining after all generation within the LBA has been dispatched goes unserved.

Proposed Solution: At a high level, the following steps will make up the proposed impact calculations

Bucket 1

1. **Serve Active Freeze Date Inter-BA TSRs**

   All freeze date resources (NRs and ERs alike) will be used to serve any sourcing Inter-BA TSRs that exist between BAs. For any such TSR in which a particular unit or LBA is listed as a source (including energy resources), that unit or LBA is decremented by the amount of gross MW associated with the TSR. In the case the source is an LBA, all generation will be collectively decremented by the gross MW associated with the TSR on a pro-rata basis. Similarly, LBA load is decremented by the gross MW of any TSR where the LBA is listed as a sink. Impacts will be calculated for each TSR that is served by multiplying the TSR MW by the TDF on each flowgate. More information on TSRs can be found in section 4.3.0.

2. **Serve Freeze Date Intra-BA TSRs**

   Freeze Date DNRs/NRs will then be used to serve any sourcing Intra-BA TSRs that exist entirely within a single BA. For any such TSR in which a particular unit or LBA is listed as a source (including energy resources), that unit or LBA is decremented by the amount of gross MW associated with the TSR. In the case the source is an LBA; all Freeze Date DNR/NRs within the LBA will be collectively decremented by the gross MW associated with the TSR on a pro-rata basis. Similarly, LBA load is decremented by the gross MW of any TSR where the LBA is listed as a sink. Impacts will be calculated for each TSR that is served by multiplying the TSR MW by the TDF on each flowgate. More information on TSRs can be found in section 4.3.0.

3. **Serve LBA Load**

   Any LBAs that still have unutilized capacity and unserved load will then dispatch Freeze Date LBA DNR/NRs within that LBA in merit order to serve the load in that LBA. More details on the merit order can be found in section 4.11.0. Impacts will be calculated for each generator by multiplying the dispatched generator MW by the Generation-to-Load Distribution Factor (GLDF) on each flowgate.

Bucket 2

1. **Serve Remaining Active Inter-BA TSRs**

   All remaining resources (DNR/NRs and ERs alike) will be used to serve any sourcing Inter-BA TSRs that exist between BAs. For any such TSR in which a particular unit or LBA is listed as a source (including energy resources), that unit or LBA is decremented by the amount of gross MW associated with the TSR. In the case the source is an LBA, all generation (DNR/NRs and ERs) will be collectively decremented by the gross MW associated with the TSR on a pro-rata basis. Similarly, LBA load is decremented by the gross MW of any TSR where the LBA is listed as a sink.

Impacts will be calculated for each TSR that is served by multiplying the TSR MW by the TDF on each flowgate. More information on TSRs can be found in section 4.3.0.

2. **Serve LBA Load**

Any LBAs that still have unutilized DNR/NR capacity and unserved load will then dispatch those DNR/NRs within that LBA in merit order to serve the load in that LBA. More details on the merit order can be found in section 4.11.0. Impacts will be calculated for each generator by multiplying the dispatched generator MW by the Generation-to-Load Distribution Factor (GLDF) on each flowgate.

3. **Serve Leftover Freeze Date Intra-BA TSRs**

To the extent that the sink point of any Freeze Date Intra BA Freeze Date TSR has unserved load and the TSR source point has excess generation, serve the TSR using any remaining DNRs/NRs and decrement those DNRs/NRs by the gross MW associated with the TSR on a pro-rata basis. Similarly, load in the sink LBA of the TSR is decremented by the gross MW of the TSR. Impacts will be calculated for each TSR that is served by multiplying the TSR MW by the TDF on each flowgate. Impacts, while calculated in the same manner as described in bucket one, will be assigned to bucket two. More information on TSRs can be found in section 4.3.0.

Bucket 3 (LBA Reliability Transfers)

This methodology is an extension of the bucket 1 and bucket 2 impact calculations. After these calculations, each BA could be left with a number of long LBAs (excess DNR/NR MWs) and a number of short LBAs (unserved load). In this scenario, the entity will be able to serve any remaining load with remaining DNR/NRs on a pro-rata basis. This entails creating a MW weighted aggregate load center with all short LBAs remaining load, and serving that load with each DNR/NR in the BA with leftover capacity on a MW weighted, pro-rata basis. The greater of these impacts and zero can be allocated in bucket 3.

Bucket 4 (BA/RTO Incremental Transfers)

The current proposal allows for two methodologies for entities to implement transfers. Entities may choose one of these methodologies on an annual basis provided they have a similar methodology employed in their planning process. The following describes the three different calculations.

1. **TSR Incremental**

This calculation methodology effectively mimics a TSR based planning approach where Long Term Firm PTP and NITS TSRs are used to calculate the effective impacts on facilities. This method makes sense for entities that plan their system using this approach. It is comprised of the following:

For each LBA:

i. Using original load values, all active sinking PTP TSR MW will decrement load values.
ii. Dispatch all NRs and ERs in merit order to serve all PTP TSRs
iii. Using adjusted load values, all sinking active NITS TSR MW will decrement load values.
iv. Dispatch DNRs in merit order to serve all active NITS TSR MW
v. Serve remaining adjusted load by dispatching remaining DNR MW in merit order to the LBA that the DNR physically resides in.
vi. Serve remaining adjusted load by dispatching remaining NR MW in merit order to the LBA that the NR physically resides in.

On a flowgate by flowgate basis, these impacts less bucket one, bucket two and bucket three impacts provide an incremental impact value. The greater of zero and these impacts can be allocated in bucket 4.

2. RTO Incremental

The RTO incremental calculation methodology consists of all BA DNR/NRs being dispatched to serve all BA load. In many RTO planning approaches, there is no distinction to an LBA. In fact, many deliverability based tests are meant to ensure a uniform level of robustness irrespective of historical BA (LBA) or Transmission Owner (TO) boundaries. This impact calculation is comprised of the following:

i. Using original load values, all active sinking Inter-BA TSR MW will decrement load values.
ii. Dispatch all DNR/NRs and ERs in merit order to serve all Inter-BA TSRs
iii. Dispatch remaining DNR/NRs in merit order to serve all BA load

On a flowgate by flowgate basis, these impacts less bucket one, bucket two and bucket three impacts provide an incremental impact value. The greater of zero and these impacts can be allocated in bucket 4.

4.6.0 *Allocation Methodology*

Description: This is the methodology for calculating entity allocations based on the calculated impacts. Impacts are separated into two categories: threshold, and non-threshold, and can be done on a directional or net basis.

For purposes in the steps below, the Adjusted Flowgate Rating is equal to the Flowgate Rating less the Transmission Reliability Margin (TRM).

Current Practice: Currently, threshold impacts are defined as those that have a 5% or greater absolute impact on the flowgate, and non-threshold impacts are defined as those that have less than 5% absolute impact on the flowgate. The following steps (in numerical order) establish the current allocation methodology:

For each direction (forward and reverse):

1. All entities allocate all threshold impacts. If there is no remaining flowgate capacity after allocating all threshold impacts, the owner is allocated the Capacity Benefit Margin (CBM) and the allocation process is finished and the flowgate is considered over allocated (more allocations than flowgate capacity)

2. However, if there is remaining capacity on the flowgate; reciprocal entities will allocate their non-threshold impacts as described below.

   - In the case the non-threshold impacts plus the CBM exceeds the remaining capacity on the flowgate, the owner will receive the CBM and the remaining capacity is allocated on a pro-rata basis using the non-threshold impacts.

   - In the case the non-threshold impacts plus the CBM is less than the remaining capacity on the flowgate, the remaining capacity is allocated on a pro-rata basis using the non-threshold impacts.

3. Any remaining capacity, after step 2 is considered firm and allocated to Reciprocal Entities based on their Historic Ratio ensuring that the owner will receive at a minimum the CBM amount. Excess allocation is further explained in the current methodology in Section 4.7.0~~4.8.0~~.

Proposed Solution: The allocation methodology consists of four different impact classifications which have been referred to as buckets in previous Sections. Each bucket is comprised of the following:

Comment [NP8]: Items to be discussed: (1) Use 0% threshold instead of 5% due to netting (2) Keep 5% threshold for FFL (3) The distribution of threshold and non-threshold impacts

1. Bucket One – Historic Impacts
   a. GTL Impacts sourcing from Freeze Date DNRs (Section 0~~4.2.0~~ – DNRs)
   b. PTP Impacts sourcing from Freeze Date TSRs (Section 0~~4.3.0~~ – TSRs)
2. Bucket Two – Post Market Integration Impacts
   a. GTL Impacts sourcing from Post Freeze Date DNRs (Section 0~~4.2.0~~ – DNRs)
   b. PTP Impacts sourcing from Post Freeze Date TSRs (Section 0~~4.3.0~~ – TSRs)
3. Bucket Three – LBA Reliability Transfers (0~~4.4.0~~ – Transfers)
   a. 6/1/2018-5/31/2023: 100 % of remaining flowgate capacity
   b. 6/1/2023-5/31/2028: 50 % of remaining flowgate capacity
   c. After 6/1/2028: 0% of remaining capacity
4. Bucket Four – TSR & RTO/BA Incremental Transfers (0~~4.4.0~~ – Transfers)

In order to phase out bucket 3 impacts in the allocation calculation, the applicable percentages shown above will be applied to any remaining flowgate capacity after buckets 1 and 2.

4.7.0 *Excess Capacity Allocation*

Description: Excess Capacity Allocation is the process of allocating the remaining capacity on a flowgate available after all entities have allocated their calculated impacts from each bucket as described in Section 4.5.0~~4.6.0~~. This situation occurs when the total of all impacts on a particular flowgate is less than the rating of the flowgate less TRM.

Current Practice: Excess capacity is socialized between reciprocal entities based on their historic ratio on the flowgate. If the owners pro-rated portion of this excess capacity is less than the CBM, the owner is allocated the CBM, and the other reciprocal entities will pro-rata allocate the remaining excess capacity based upon their historic ratio. If the owners pro-rated portion of this excess capacity is greater than or equal to the CBM, all reciprocal entities receive this pro-rated excess allocation.

Proposed Solution: The proposed solution is that the owner of the flowgate will receive allocations for any excess capacity. This will ensure the owner of the flowgate has the first priority on its own transmission system.

4.8.0 *Addressing Parallel Flows Through Planning*

Comment [RA9]: Further review required and discussion with TVA

Description: Parallel flows are unavoidable particularity as generation interconnects to the network. Ideally, parallel flows can be fully accounted for during the planning process for generator interconnections, load deliverability and market efficiency. However, due to the different planning processes and requirements between the different entities, the measured amount of parallel flows and upgrades necessary to reduce or remove these parallel flows may be different. It is important to provide appropriate incentives for entities to plan the transmission system sufficient for their own needs while limiting or recognizing the parallel flows on other systems. Ideally, entities that have funded the transmission system should have the right to use that system capability.

Current Practice: Depending on the entity, allocations for parallel flows could be granted to the entity that caused the parallel flows. This dependency exists because the different entities have different planning process, coordinated efforts and interconnection requirements. Although the parallel flows may be the result of interconnected operations, the allocations for these flows on the transmission facilities of the neighboring system are granted to the entity that is assigned the DNR. The allocations are granted via several mechanisms. First, the CMP may allow a Transmission Upgrade Studies Process (TUS) to compensate entities in the form of increased allocations to those who build transmission. This process ensures the building entity can acquire allocations for transmission it funds. Second, coordinated planning efforts are in place between entities to ensure that generator interconnections that impact neighboring areas can be studied appropriately and trigger necessary upgrades. Third, coordinated market efficiency efforts should ideally result in joint funded upgrades based on the benefits realized by each market. These joint upgrades will result in allocations to the entities consistent with cost allocation of the transmission upgrade. Admittedly, these three mechanisms are not the same between the different entities and may not be robust enough to ensure parallel flows are accounted for properly.

Proposed Solution: The solution to resolve parallel flow impacts starts with the planning process. Today planning processes and coordinated efforts are different between each entity. A comparable treatment of planning and coordinated efforts will be needed to resolve how the parallel flows on other systems will be limited or recognized. For example, PJM and MISO will need to ensure their coordinated planning efforts are robust enough and satisfactory similar to how SPP and MISO will need to do the same. After a review between all the coordinated entities, the following conclusion and solution is proposed.

***PJM-MISO*:** PJM and MISO have reviewed their planning processes and impacts to parallel flows on neighboring systems with respect to allocations and have concluded that the current or pending processes are sufficient. These processes, existing or pending, already include, as described in the PJM-MISO JOA, coordinated generation interconnection studies, targeted market efficiency analysis, interregional market efficiency analysis and modeling of external flow impacts in load deliverability analysis. In addition, the TUS process supplements these planning processes to ensure allocations align with the entity that builds or funds an upgrade.

MISO-SPP: MISO and SPP have reviewed their planning processes and impacts to parallel flows on neighboring systems with respect to allocations and have ongoing discussions committed to pursue planning process and cost allocation changes. MISO and SPP already have coordinated efforts for generation interconnection and market efficiency and need to ensure that their respective studies for generator interconnection and transmission service (including network load deliverability studies) include provisions for coordinating with impacted Parties' transmission system consistent with how that Party evaluates its own transmission system in those processes. MISO and SPP are committed to develop a process to address regional cost allocation voltage differences (including projects down to 100 kV). In addition, SPP and MISO intend to pursue adopting a similar effort that PJM and MISO have with the targeted market efficiency analysis by the end of 2017. MISO and SPP have committed to pursue the interregional process and cost allocation changes with an anticipated effective date of January 1, 2019 pending the outcome of SPP and MISO's regional and interregional stakeholder processes.

Non-Market Entities: To be determined.

4.9.0 *Capping FFE/FFL*

Description: Whether logic will be in place that caps the total FFE/FFL value at the line rating.

Current Practice: Values are not capped.

Proposed Solution: Allocating on a net basis should drastically reduce occurrences where a flowgate is over-allocated. In the event it still occurs, values will be capped to prevent reliability issues.

4.10.0 *Run Types*

Description: In order to provide values in forward looking planning processes and markets such as Capacity Markets, FTR Markets, and Day Ahead Markets, the entitlement calculation is rerun using load and topology values that represent these forward looking horizons.

Current Practice: Currently, the following forward looking horizons are used to specify a load and topology forecast:

- Summer Seasonal (effective 6 months to 18 months in advance)
- Winter Seasonal (effective 6 months to 18 months in advance)
- Monthly (effective next 6 consecutive months)
- Weekly (effective next 7 days)
- 2 Day-Ahead (effective day after tomorrow)
- Day –Ahead (effective tomorrow)

Proposed Solution: Status Quo, further discussion required to consider peak/off peak and wind.

4.11.0 *Merit Order*

Description: Merit order refers to the way in which generators are prioritized in each bucket.

Current Practice: The practice now assigns a merit order number (1-500) to each generator that has "DNR status" as of the Freeze Date. Generators without DNR as of the Freeze Date status have a priority of zero. Generators are dispatched to meet LBA load in order from lowest (one) to highest (500). If there is still load remaining after dispatching the generators with a non-zero priority, priority zero units are dispatched pro rata within the LBA up to the remaining load.

Proposed Solution: Further discussion is needed on the modifying of merit orders. Each Balancing Authority is responsible for creating its own merit order dispatch on a BA basis. Since it is possible two portions of the same unit can fall under two different buckets, each portion of the unit will be listed as a separate unit, with each record designating which bucket that portion is classified under. Priority should be determined on a BA basis, with the idea that generators in any given LBA will be in the same sequential order when grouped in the LBA as they will be in the BA.

The table below shows an example:

Generator Name	Machine Id	Owner	Bucket	PMin	PMax	Part. Factor	Resource	Loading Priority
01AL DAM5 4.1600	1	PJM	2	0	2.5	1	YES	6
01AL DAM5 4.1600	2	PJM	2	0	2.5	1	YES	7
01AL&D6 138.00	1	PJM	1	0	3	1	YES	4
01AL&D6 138.00	1	PJM	2	0	1	1	YES	4

Table 6 – Merit Order Example

Note that each partial unit will have its own merit order curve, but for simplicity, block priorities were shown. Merit Orders will be established using some form of economic or run-time based analysis.

4.12.0 *Out of Scope Items*

Out of scope items, while not part of the freeze date resolution embodied in this straw proposal, are being evaluated by the CMPWG in parallel to the freeze date.

1. **Topology**

   Description: Used to calculate shift factors to determine generator and TSR/Transfer impacts.

   Current Practice: Currently updated to use latest IDC case twice a year with the NNL model update.

   Proposed Solution: Status quo, however, the parties agree to keep a similar methodology, will continue to discuss, update frequency and automation.

2. **Incremental Upgrades**

   Description: Methodology for obtaining additional entitlements for upgrading the system.

   Current Practice: Transmission Upgrade Studies (TUS) and Appendix G to the JOA

   Proposed Solution: Current practice will remain in place; however, additional language will be added to Appendix G and TUS for clarification purposes beyond the scope of the Freeze Date Update.

3. **Pseudo-Ties**

   Description: Pseudo-Tie generation is physically located outside the BA for which it is serving load. Pseudo-Tie load is physically located outside the Balancing Authority for which it is absorbing generation. Pseudo-Tie resources, as defined per NERC is "a time-varying energy transfer that is updated in Real-time and included in the *Actual Net Interchange term* (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes)". Pseudo-Tie resources, unlike Dynamic Schedules, are historically subject to the attaining BA's operational, generation planning and outage coordination. NERC INT-004 standard requires that entities include pseudo-tied generating resource impacts in its congestion management process. These resources may be dispatched to address congestion for internal transmission and external coordinated flowgates. Pseudo-Tie resources are required to obtain Firm PTP service for the flow impacts from the physical unit to the border between the native and attaining BA. The native BA is where the Pseudo-Tie is physically located. The attaining BA is where the Pseudo-Tie is transferring energy/load to.

   Current Practice: Existing Pseudo-Tie resources are modeled as part of the native BA where they are physically located. Therefore, the allocations are granted to the native BA. Specific provisions exist today and outline the circumstances in which a Pseudo-Tie resources transfer allocations. Certain exceptions have been made with CMPWG approval for Pseudo-Tie resources that had long standing Power Purchase Agreements (PPA) that pre date the Freeze Date to serve load in the attaining BA (such as Joint Owned Units).

   Proposed Solution:

   Market Entities: To be determined.

   For Non-Market Entities the following rules apply:

   Pseudo-Tie allocations will be assigned to the attaining BA in Bucket 2 as a post Freeze Date resource. The allocations may qualify as a Bucket 1 Freeze date resource if there is a specific load obligation where a Freeze Date TSR existed.

4. **Freeze Date TSR List Management**

Description: The freeze date TSR list is used to represent the transmission rights that existed on the historic transmission system.

Current Practice: The existing tool has the TSRs that existed as of the Freeze Date and develops the Freeze Date TSR list that is applicable for each CMP entities flowgates.

Proposed Solution: Current practice will remain in place but modifications need to be developed for the tool.

5.0 Implementation Plan- To be determined.