NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

**Consideration of Comments — 2nd Draft of Standard MOD-028-1 — Network Response ATC (Project 2006-07)**

The ATC Standard Drafting Team requesters thank all commenters who submitted comments on the first draft of standard MOD-028-1, Network Response (Project 2006-07). This standard was posted for a 30-day public comment period from May 25 through June 24, 2007. The requesters asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 17 sets of comments, including comments from 76 different people from more than 40 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team has significantly redrafted the standard. The drafting team has addressed a significant number of the concerns expressed, but the changes have been so extensive that the revised standard bears very little resemblance to the last posted draft. Major changes include:

- A new term was defined to support a change in the name of the methodology described in the standard – Area Interchange Methodology
- The title was changed from, 'Network Response ATC' to 'Area Interchange Methodology' to have a title that is more self-descriptive.
- The Purpose statement was enhanced to clarify that the standard's purpose is to 'increase consistency and transparency in the development of transfer capability calculations' rather than to 'increase consistency and transparency in the development and documentation of ATC.'
- The Applicability was modified to eliminate the Planning Coordinator and Reliability Coordinator and to add the Transmission Operator. R1, which required the Planning Coordinator and Reliability Coordinator to provide specific information about contingencies and assumptions used to determine Transfer Capabilities to the Transmission Service Provider was eliminated. The intent of the requirement was to ensure that these contingencies and assumptions were respected by the Transmission Service Provider in the determination of TTC – and in the revised standard's R1, the Transmission Service Provider must document these contingencies, and other information used in the calculation of TTC in the Transmission Service Provider's Available Transfer Capability Implementation Document.
- R2, R3, R8 and R16 all required the Transmission Service Provider to make information publicly available, and all four of these requirements have been deleted from the revised standard. NAESB's business practices will address all ATC-related posting requirements.
- R4 which required the Planning Coordinator and Reliability Coordinator to ensure that TTC for each of the Transmission Service Provider's paths was calculated according to a schedule has been deleted. All requirements for the Planning Coordinator and Reliability Coordinator to calculate TTC have been removed from the standard and have been replaced with more detailed requirements for the Transmission Service Provider and/or the Transmission Operator to calculate TTC.
- R5 which required the Planning Coordinator and Transmission Operator to update the models used to calculate TTC has been revised so that the requirement is applied to the

Transmission Operator. The various components of the model that must be updated have been modified to provide more specificity to the elements of the model that must be used in calculating TTC.

- R6 outlined a process for the Planning Coordinator and Reliability Coordinator to follow in determining TTC for a path – and this requirement has been modified so that it applies to the Transmission Operator. The steps in the process have been modified to improve the clarity of the steps in the process.
- R7 required the Planning Coordinator and Reliability Coordinator to provide the Transmission Service Provider with the TTCs they had calculated – and this requirement has been revised so that it applies to the Transmission Operator. In the revised requirement, the Transmission Operator must make the TTCs it has calculated available to the Transmission Service Provider within five days of the determination of those TTCs.
- R9, R10 and R13 required the Transmission Service Provider to calculate ATC in accordance with very high-level formulas and requirements in MOD-001. In the revised standard there is a very detailed formula for calculating Firm ATC (R10) and a very detailed formula for calculating Non-Firm ATC (R11).
- R11 required the determination of Firm ETC in accordance with a set of 'inputs'. This requirement has been modified so that it includes a very detailed formula for calculating Firm ETC (R8).
- R12 required the Transmission Service Provider to limit the total impact of all transmission service from a specific POR to not exceed the sum of the nameplate ratings of all generators at that POR. The drafting team could not find a reliable approach to specifying how this could be implemented and the requirement was deleted.
- R13 and R15 were 'rules' relative to the calculation of ATC and have been deleted as separate requirements – they are now addressed in the algorithm for calculating non-firm ATC in the revised standard (R12).
- R14 required the determination of Non-Firm ETC in accordance with a high level formula. This requirement has been modified so that it includes a very detailed algorithm for calculating Non-Firm ETC (R9).
- Added measures and compliance information.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/MOD-V0-Revision.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Anita Lee (G2) | AESO | | ✓ | | | | | | | | |
| 2. | Darrell Pace (G7) | Alabama Electric Coop. | | | | ✓ | ✓ | ✓ | | | | |
| 3. | Helen Stines (G7) | Alcoa Power Generating, Inc. | | | | | | ✓ | ✓ | ✓ | | |
| 4. | Ken Goldsmith | ALT | ✓ | | | | ✓ | | | | | |
| 5. | Eugene Warnecke (G7) | Ameren | | | ✓ | | | ✓ | | | | |
| 6. | E. Nick Henery | APPA | ✓ | | ✓ | ✓ | | | | | | |
| 7. | Dave Rudolph | BEPC | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 8. | Abbey Nulph | Bonneville Power Administration (BPA) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 9. | Brent Kingsford (G2) | CAISO | | ✓ | | | | | | | | |
| 10. | Don Reichenbach (G7) | Duke Energy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 11. | Greg Rowland | Duke Energy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 12. | Joachim Francois (G7) | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 13. | Ed Davis | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 14. | George Bartlett | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 15. | Jim Case | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 16. | Narinder K Saini | Entergy Services Inc. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 17. | Steve Myers (I) (G2) | ERCOT | | ✓ | | | | | | | | ✓ |
| 18. | Dave Folk | FirstEnergy Corp. | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 19. | Phil Bowers | FirstEnergy Corp. EDPP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 20. | Richard Kovacs | FirstEnergy Corp. EDPP | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 21. | Ross Kovacs (G7) | Georgia Transmission Corporation | ✓ | | ✓ | | | | | | | |
| 22. | Joe Knight | Great River Eenergy | ✓ | | ✓ | | ✓ | | | | | |
| 23. | Danielle Beaulieu | Hydro-Québec TransÉnergie | ✓ | | | | | | | | | |
| 24. | Roger Champagne (G4) | Hydro-Québec TransÉnergie (HQT) | ✓ | | | | | | | | | |
| 25. | Ron Falsetti (I) (G2) | IESO | | ✓ | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 26. | Charles Yeung (G2) | IRC Standards Review Committee | | ✓ | | | | | | | | |
| 27. | Matt Goldberg (I)(G2) | ISO New England (ISO NE) | | ✓ | | | | | | | | |
| 28. | Kathleen Goodman (G4) | ISO New England (ISO NE) | | ✓ | | | | | | | | |
| 29. | Eric Ruskamp | LES | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 30. | Robert Coish (G3) | Manitoba Hyrdo EB | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 31. | Jerry Tang (G7) | MEAG | ✓ | | ✓ | | ✓ | | | | | |
| 32. | Tom Mielnik (I) (G3) | MidAmerican Energy Company (MEC) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 33. | Dennis Kimm (G3) | MidAmerican Energy Generation/Trading (MEC Trading) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 34. | Larry Middleton (G7) | Midwest ISO | | ✓ | | | | | | | | |
| 35. | Carol Gerou | Minnesota Power (MP) | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 36. | Bill Phillips (G2) | MISO | | ✓ | | | | | | | | |
| 37. | Terry Bilke (G3) | MISO | | ✓ | | | | | | | | |
| 38. | Mike Brytowski | MRO | | | | | | | | | | |
| 39. | Greg Campoli (G4) | New York ISO (NYISO) | | ✓ | | | | | | | | |
| 40. | Jim Castle (G2) | New York ISO | | ✓ | | | | | | | | |
| 41. | Ralph Rufrano (G4) | New York Power Authority (NYPA) | ✓ | | ✓ | | | | | | | |
| 42. | Al Adamson (G4) | New York State Reliability Council | | | | | | | | | | ✓ |
| 43. | Matt Schull (G1) | North Carolina MPA #1 | | | ✓ | ✓ | ✓ | ✓ | | | | |
| 44. | Guy V. Zito | NPCC WG | | | | | | | | | | |
| 45. | Alicia Daugherty (G2) | PJM | | ✓ | | | | | | | | |
| 46. | C. Robert Moseley (G5) | PSC of South Carolina (PSC SC) | | | | | | | | | ✓ | |
| 47. | David A. Wright (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 48. | G. O'Neal Hamilton (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 49. | John E. Howard (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 50. | Mignon L. Clyburn (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 51. | Phil Riley (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 52. | Randy Mitchell (G5) | PSC of South Carolina | | | | | | | | | ✓ | |
| 53. | John Troha (G7) | SERC ATCWG | | | | | | | | | | ✓ |
| 54. | Carter Edge (G7) | SERC RC | | | | | | | | | | ✓ |
| 55. | Al McMeekin (G7) | South Carolina Electric & Gas Co. | | | ✓ | | ✓ | ✓ | | | | |
| 56. | Stan Shealy (G7) | South Carolina Electric & Gas Co. | | | ✓ | | ✓ | ✓ | | | | |
| 57. | Bryan Hill (G7) | South Carolina Services | ✓ | | | | ✓ | | | | | |
| 58. | Bill Botters (G6) | Southern Company Services (SCS) | ✓ | | | | ✓ | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 59. | Chuck Chakravarthi (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 60. | Dean Ulch (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 61. | DuShaune Carter (G6) (G7) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 62. | Garey Rozier (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 63. | Gary Gorham (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 64. | Jeremy Bennett (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 65. | Jim Howell (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 66. | Jim Viikinsalo (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 67. | JT Wood (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 68. | Karl Moor (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 69. | Marc Butts (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 70. | Reed Edwards (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 71. | Roman Carter (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 72. | Ron Carlsen (G6) | Southern Company Services | ✓ | | | | ✓ | | | | | |
| 73. | Doug Bailey (G7) | TVA | ✓ | | ✓ | | ✓ | | | | | |
| 74. | Jim Haigh | WAPA | ✓ | | | | | ✓ | | | | |
| 75. | Neal Balu (G3) | WIPS | | | | | | | | | | |
| 76. | Pam Oreschnick | XEL | ✓ | | ✓ | | ✓ | ✓ | | | | |

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – APPA
G2 – IRC Standards Review Committee
G3 – MRO Group Members
G4 – NPCC CP9 Working Group
G5 – PSC of South Carolina
G6 – Southern Company Servies
G7 – SERC Available Transfer Capability Working Group (ATCWG)

## Index to Questions, Comments, and Responses

1. The drafting team attempted to address all of the directives identified in the Federal Energy Regulatory Commission's (FERC) Orders 890 and 693 related to ATC and TTC. Do you agree that the drafting team has adequately responded to all of FERC's directives in FERC Orders 890 and 693 related to ATC/TTC in this draft of MOD-028-1? If "No," please identify which directives were 'missed' in the comments area.

**Summary Consideration:** None of the stakeholders who responded to this question provided a specific directive from either of the FERC Orders relative to MOD-028 that was missing in the proposed MOD-028. Several stakeholders expressed concerns that insufficient time had been allocated to fully review the Orders against the proposed standard. The Drafting Team met with members of FERC staff to gain more insight into the directives in the two Orders and determined that some directives needed additional attention – and the drafting team remedied this in draft 2 of the proposed standard. The drafting team will post a matrix that shows each of the directives and identifies the standard and requirement where the directive has been addressed.

| **Question #1** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | The Federal Energy Regulatory Commission (FERC) has requested Standards that determine the requirements to calculate TTC will be handled in the FAC Standards. Order 693 States the following: 1050. We adopt the NOPR proposal and require that TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0. The FAC series of standards contain the Reliability Standards that form the technical and procedural basis for calculating transfer capabilities. FAC-008-1 provides the basis for determining the thermal ratings of facilities while FAC-009-1 provides the basis for communicating those ratings. FAC-010-1 and FAC-011-1 provide the system operating limits methodologies for the planning and operational horizon respectively and FAC-014 provides for the communication of those ratings.<br><br>FERC has correctly recognized that FAC-012 and FAC-013, while associated with modeling is highly dependent on the previous FAC Standards as noted by FERC. |
| **Response:** FERC has provided the Drafting Team additional guidance regarding this area. The TTC Standard will be moved from the FAC standards to the MOD standards. | | | |
| Duke Energy | | ☑ | Conditional Firm Service (CFS) and Planning Redispatch Service (PRS) under Order No. 890 create new issues relating to modeling and calculating ATC. Specifically, when PRS is offered to maintain service, modeling for ATC calculations will be impacted during these periods. TTC must be modeled/calculated accounting for the new CFS/PRS requirements. |
| **Response:** It is important to note that Planning Redispatch and CFS are only offered to long-term (one year or longer) service requests and that these two service types are considered firm when ATC is available in the short-term horizons. We believe this will be handled as a part of the NAESB work. | | | |
| MEC Trading | | ☑ | The entire point of 890 and 693 appeared to be not only for transparency, but consistency. |
| **Response:** Agree. The SDT thanks you for your comments. | | | |
| NPCC WG | ☑ | ☑ | We believe the fundamental concerns of the FERC Orders 890 and 693 are identified in the standard. |

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| HQT | | | However, there are many detailed requirements in Orders 890 and 693 such that there has not been adequate time to do a thorough comparison. It is expected that the supplemental SAR would be addressing the issues that remain outstanding from those Orders. |
| **Response:** The SDT thanks you for your comments. The drafting team will post a matrix that shows each of the directives and identifies the standard and requirement where the directive has been addressed. | | | |
| ISO NE | ☑ | ☑ | We believe the fundamental concerns of the FERC Orders 890 and 693 are identified in the standard. However, there are many detailed requirements in Orders 890 and 693 such that there has not been adequate time to do a thorough comparison. |
| **Response:** The SDT thanks you for your comments. The drafting team will post a matrix that shows each of the directives and identifies the standard and requirement where the directive has been addressed. | | | |
| IESO | ☑ | ☑ | We agree that the drafting team appears to have addressed all the FERC directives. However, we feel that this and the other MOD standards need revisions to properly align responsibilities and eliminate duplications (also see our comments on the other MOD standards). |
| **Response:** The drafting team looked for these examples and considered this when modifying the standards. The drafting team did modify the applicability of this and other standards in support of the stakeholder comments indicating that some of the requirements had been in appropriately applied to the Planning Coordinator and Reliability Coordinator. | | | |
| IRC | ☑ | ☑ | We agree that the drafting team appears to have addressed all the FERC directives. However, we feel that this and the other MOD standards need revisions to properly align responsibilities and eliminate duplcations (also see our comments on the other MOD standards). We should resist this question again when updated standard versions are posted. |
| **Response:** The drafting team looked for these examples and considered this when modifying the standards. The drafting team did modify the applicability of this and other standards in support of the stakeholder comments indicating that some of the requirements had been in appropriately applied to the Planning Coordinator and Reliability Coordinator. | | | |
| ERCOT | ☑ | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** See the response to IRC's comments. | | | |
| Entergy | ☑ | | |
| FirstEnergy | ☑ | | |
| MEC | ☑ | | |
| MRO | ☑ | | |
| PSC SC | ☑ | | |
| SCS | ☑ | | |
| SERC ATCWG | ☑ | | |

2. Do you believe that all elements of ETC have been adequately captured in Requirements eleven and fourteen (R11 and R14)? If "No," please explain why in the comments area.

**Summary Consideration:** The SDT made several changes to the standard to address the comments received, including the following:
Modified R8 (now

Modified R11 (now R8) so that instead of requiring the Transmission Service Provider to 'determine the impact' of firm ETCs based on a set of inputs, the Transmission Service Provider must use the following algorithm to 'calculate' Firm ETC:

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Modified R14 (now R11) so that instead of requiring the Transmission Service Provider to 'determine the impact' of Non-firm ETCs based on a set of inputs, the Transmission Service Provider must use the following algorithm to 'calculate' Non-Firm ETC:

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + Counterflows_{NF}$$

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | This Standard is trying to detail the requirements of ETC and TTC in the same document. A large amount of the sub requirements in R11 and R14 are incorrect and/or being preformed by the wrong Applicable Function. The formula for Non-Firm ATC is incorrect and cannot be complied with by the Applicable Function listed. |
| **Response:** The drafting team considered this when modifying the standards, and redrafted the standard in hopes of addressing your concerns.<br>R11 and R14 required the TSP to determine the impact of firm and non-firm ETC – and the TSP is the functional entity that should perform these calculations, so the applicability was not changed.<br>The drafting team did revisit the sub-requirements for determining ETCs and converted the 'inputs' into elements in algorithms. Please see the Summary Consideration. | | | |
| BPA | | ☑ | The impact of load growth for Network Integration Transmission Service should be included in R11.2.<br><br>The "five years or longer in duration" language should be removed from R11.5. due to the fact that this element of Order 890 is only to be implemented by a Transmission Service Provider (TSP) once the FERC has approved the TSP's Attachment K -- this may not occur for some TSPs until after the standards are to be implemented. Additionally, regardless of whether a TSP's Attachment K is approved, there will be a transition period (to be developed by each TSP) from the old 1-year/60-day |

| Question #2 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | roll-over paradigm to the 5-year/1-year -- the standard should not preclude a TSP from encumbering capacity for those existing Customers who have not yet been required to commit to five years of service to retain their roll-over rights. |
| **Response:** The SDT modified the format of the requirement so that it requires the use of an algorithm rather than requiring the use of 'inputs'. In the revised requirement, 'Firm Network Integration Transmission Service' is one element in the Firm ETC algorithm, defined as the firm capacity reserved for network integration transmission service reserved on Posted Paths that serve as interfaces with other Transmission Service Providers.<br>The SDT has removed the timeframe noted in R11.5. (See the algorithm in R8 in the revised standard- the revision is in the definition of Firm Roll Over Rights.) | | | |
| Duke Energy | | ☑ | R11.4 should read as follows: The impact of Firm Point to Point Transmission Service adjusted for Post-backs.<br>R11.5 should read as follows: The impact of maintaining roll-over rights for Long-Term Firm Transmission Service contracts.<br>R11.6 should be deleted or replaced with more specific details of what Ancillary Services impacts are to be considered.<br>R11.7 should be deleted, since this is now included in R11.4 above.<br>R11.8 should be deleted or replaced with more specific details of how counterflows should be included.<br>R11.9 should read as follows: The impact of any other services, contracts, or agreements not specified above using transmission that serves Native Load or Firm Network Integration Transmission Service, adjusted for Post-backs.<br>R14.3 should read as follows: The impact of Non-Firm Point to Point Transmission Service, with adjustments for Post-backs.<br>R14.4 should be deleted or replaced with more specific details of how counterflows should be included.<br>R14.6 should be deleted, since this is now included in R14.3 above. |
| **Response:**<br>The SDT incorporated the intent of the R11.4 suggestion by changing, 'Firm Point to Point Transmission Service' to 'Firm capacity reserved for confirmed Point-to-Point Transmission Service'.<br><br>The SDT incorporated the intent of the R11.5 suggestion by changing the requirement so that instead of 'determining the impact of maintaining roll-over rights' the revised standard requires use of an algorithm to calculate ETC for Firm Commitments - and one element in the algorithm is 'Firm Roll-over Rights' – defined as the 'capacity reserved for roll-over rights for Firm Transmission Service contracts . . . '<br><br>The SDT incorporated the intent of the R11.7 through R11.9 in the revisions made to modify what had been R11.9 – in the revised standard, the algorithm for calculating Firm ETC has an element called, '$OS_F$' – defined as the capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other | | | |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| firm adjustments to reflect impacts on other Posted Paths as described in the ATCID. With this revision, the intent of what had been R11.6, R11.7, R11.8 and R11.9 have been addressed in the determination of $OS_F$.<br>The SDT modified MOD-001 – Available Transfer Capability to include specific requirements that (R 4 and R5) that specify how to determine the impact of counterflows when determining firm and non-firm ATC. In addition, the revisions to MOD-001 require the Transmission Service Provider to prepare a document (called ATCID) that includes information about the methodology used to determine ATC, and one of the new requirements states that the Transmission Service Provider must document, in its ATCID, how it accounts for counterflows.<br><br>R14.3 – The SDT incorporated the intent of the suggestion by changing, 'Non-Firm Point to Point Transmission Service' to 'Non-Firm capacity reserved for confirmed Point-to-Point Transmission Service'.<br><br>R14.4, R14.6 - in the revised standard (see R9), there is an algorithm for calculating Non-Firm ETC with an element called, '$OS_{NF}$' – defined as the capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts on other Posted Paths as described in the ATCID. With this revision, the requirements that had been included in R14.4, R14.5, and R14.6 are addressed in the determination of $OS_{NF}$. | | | |
| Entergy | | ☑ | R.12 is part of ETC for Firm ETC and R15 is adjustment to the Non-Firm ETC which is similar to post back of capacity, therefore, these should be included as sub bullets under R11 and R14 respectively. |
| **Response:**<br>The SDT could not find a reliable approach to specifying how this should be implemented and the requirement (R12) was removed. | | | |
| IESO | | ☑ | We feel that R11.1, R11.2, R11.6 and R14.1 leave room for double counting of components that shold have been taken care of by TRM and CBM. Further, we do not understand why the CBM component is excluded from R13. If the omission is based on the rationale that CBM could be offered as non-firm ATC, then wouldn't TRM be treated in the same manner? |
| **Response:** The drafting team made significant modifications to this standard to eliminate opportunities for double counting – and one of the significant modifications was to formalize the algorithms for calculating ETC. The revised standard is more specific, and instead of requiring the Transmission Service Provider to determine the 'impact of firm ETC's' the revised standard includes the following algorithm for calculating Firm ETC and includes a definition of each of the elements used in the algorithm:<br><br>$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$<br><br>R11.1, which addressed native load commitments, was removed from the standard.<br>R11.2 was which focused on the 'impact' of Firm Network | | | |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| IRC | | ☑ | We feel that R11.1, R11.2, R11.6 and R14.1 leave room for double counting for components that shold have been taken care of by TRM and CBM. |
| **Response:** The requirement language was modified such that these comments are not applicable to the current version of the standard. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** Please see the response to IRC's comments. | | | |
| ISO NE | | ☑ | We suggest rephrasing R11 and R14 so that it also states that: "The TSP shall determine the impact of firm ETCs based on the inputs listed below. If any of the inputs listed below refer to a product or service that is not contained in the TSP's FERC-approved Tariff, the TSP shall document this fact in their ATCID and the value of such input(s) in the ETC calculation shall be considered to be zero MW."<br><br>The wording of 11.8 and 14.4 imply that the TSP MUST include the impact of counterflow. We do not agree that the impact of counterflow MUST be considered. It should up to the TSP as to if, when and how counter flow is considered. The requirement should be worded to allow for that flexibility and require that the TSP document how it is considered. |
| **Response:** The suggested language for ETC was not adopted since the standard allows for each ATCID to document how the components are determined. If the component is not applicable due to the TSP tariff, the ATCID can describe that and the suggested language is not required to be in the standards for that to occur.<br><br>The DT is following FERC guidance on establishing consistency and defines default treatment of counterflow in the standard. If a TSP has reliability reasons for doing something different, they can include that description in their ATCID. | | | |
| MEC<br>MRO | | ☑ | 1. R11 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm existing transmission committements based on an appropriate level of the following inputs."<br>2. Existing transmission commitments should not be listed in capatalized letters unless a definition is going to be developed for the NERC Glossary. |
| **Response:** The DT believes "appropriate level" is too vague to be measured objectively. When determining ETC, impacts of all Firm commitments should be noted.<br>ETC is capitalized because it is an acronym, and we have added a definition. | | | |
| FirstEnergy | ☑ | | However the term "Post-backs" is industry jargon and should be replaced with the term "reinstatement" to add clarity., |
| **Response:** We have included the term postback and it is intended that NAESB work to clarify what is included in postbacks. | | | |
| MEC Trading | ☑ | | |
| PSC SC | ☑ | | |
| SCS | ☑ | | |

3. The drafting team attempted to clearly identify the functional classes of entities responsible for complying with the proposed draft MOD-028-1 standard. Do you agree with the functional entities identified in the "Applicability" section of the draft standard? If "No," please identify the functional entities you believe the standard should apply to in the comments area.

**Summary Consideration:** Many stakeholders who responded to this question disagreed with the proposed applicability. The SDT has redrafted the standard after significant study of the functional model to address these concerns and the revised standard does not have any requirements applied to either the Planning Coordinator or the Reliability Coordinator.

| **Question #3** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| MEC Trading | | | This is very difficult because the functional model seems to be very specific, but roles within a utility are not so clearly defined. |
| **Response:** The SDT agrees that it can be difficult to apply the functional model to a specific entity. | | | |
| MRO | | ☑ | The MRO believes that the Functional Entity as provided in A.4. should not be qualified, for example, the MRO recommends that A.4. just list Planning Coordinator, Reliability Coordinator, and Transmission Service Provider. |
| **Response:** Per the guidance provided by the NERC standards staff, the 'Applicability' section of the standard should always identify any limitations associated with the applicability. MOD-028 only applies to entities that use the network response methodology of calculating ATC. | | | |
| MEC | | ☑ | The Functional Entity as provided in A.4. should not be qualified, for example, A.4. should just list Planning Coordinator, Reliability Coordinator, and Transmission Service Provider. |
| **Response:** Per the guidance provided by the NERC standards staff, the 'Applicability' section of the standard should always identify any limitations associated with the applicability. MOD-028 only applies to entities that use the network response methodology of calculating ATC. | | | |
| SERC ATCWG | | ☑ | The applicability section needs clarification. Referencing R4 and R5, they should apply only to those entities performing the function. The standard should not require the calculations be made by the PC and RC, but should be applicable to the designated entitiy performing these calculations . The designated entity must be specified as a requirement in this standard. For example: The TSP, PC and RC must specify and agree to the entity that performs this function in the TSP's ATCID as required in MOD 1. The current revision of MOD-001 states the following requirement as R1: "Each Transmission Service Provider, and its associated Planning Coordinators and Reliability Coordinators, shall agree upon and implement one or more of the ATC methodologies specified in Reliability Standard MOD-028, MOD-029, and MOD-030 for use in determining Transfer Capabilities of those Facilities under the tariff administration of that Transmission Service Provider." The requirements of MOD-0028 should refer to the Designated Entity specified through this requirement. The following are examples of how this would be implemented in the standard:<br>B. Requirements<br>R4. Each Designated Entity shall ensure that the Total Transfer Capability (TTC) for each of its |

| Question #3 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | Transmission Service Provider's POR to POD Paths is calculated and up-to-date for use within the Transfer Capability time horizons specified in MOD-001 R2.<br>R5. Prior to calculating TTC, each Designated Entity shall update the following components of the base case power flow model it uses to calculate TTC for the time horizon being studied: |
| **Response:** The SDT has redrafted the standard after significant study of the functional model to address these concerns.<br>The drafting team revised MOD-001 — Available Transfer Capability so that R1 has been deleted from the revised set of standards, and MOD-001 no longer has any requirement assigned to either the Planning Coordinator or the Reliability Coordinator.<br>The revised MOD-028 does not have any requirements applied to either the Planning Coordinator or the Reliability Coordinator.<br>The Functional Entity may delegate tasks but the responsibility remains with the Registered Entity, so adding a new term and assigning requirements to that new 'function' is not an acceptable modification. The standard must identify the same functional entities that register in NERC's compliance registry. | | | |
| APPA | | ☑ | As stated in comment no. 1, TTC is directed to be handled in the FAC series Standards. Therefore the Applicable Functions are incorrect. |
| **Response:** MOD-028, MOD-029 and MOD-030 include the appropriate requirements for total transfer capability as they apply to each ATC methodology. All requirements that were included in FAC-012 and FAC-013 are now incorporated into the MOD standards. | | | |
| BPA | | ☑ | "Planning Coordinator" is not defined in the NERC Glossary of Terms Used in Reliability Standards. Please clarify what the Planning Coordinator is or replace "Planning Coordinator" with Planning Authority. |
| **Response:** MOD-028 and the ATC calculations are limited to the 13 month timeframe and Planning Coordinator is no longer included in the standard. | | | |
| IESO<br>IRC | | ☑ | The Planning Coordinator and Reliability Coordinator do not calculate ATCs. We suspect the reason that they are included in the applicability section is for their role in determining TTC. However, their roles are incorrectly stated in the applicability description. |
| **Response:** The SDT has redrafted the standard after significant study of the functional model to address these concerns.<br>The revised MOD-028 does not have any requirements applied to either the Planning Coordinator or the Reliability Coordinator. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** Please see the response to IRC's comments. | | | |
| HQT<br>NPCC WG | ☑ | ☑ | We agree with the entities listed. However, the description of the applicability for the PC and RC are not valid. The PC and RC provide input to ATC calculations, but they do not calculate ATCs. Suggest replacing 'ATCs' with 'TTCs' in the description of Requirement 4.1 and 4.2. |

| Question #3 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | Also, the language in these Applicability descriptions should be the consistent between MOD-028 and MOD-029. |
| **Response:** The SDT has redrafted the standard after significant study of the functional model to address these concerns. The revised MOD-028 does not have any requirements applied to either the Planning Coordinator or the Reliability Coordinator.<br>The descriptive language in the applicability section of MOD-028 was already used in MOD-029 and MOD-030. | | | |
| ISO NE | ☑ | ☑ | We agree with the entities listed. However, the description of the applicability for the PC and RC are not valid. The PC and RC provide input to ATC calculations, but they do not calculate ATCs. Suggest replacing 'ATCs' with 'TTCs' in the description. |
| **Response:** The SDT has redrafted the standard after significant study of the functional model to address these concerns. The revised MOD-028 does not have any requirements applied to either the Planning Coordinator or the Reliability Coordinator. | | | |
| Entergy | ☑ | | Applicability section correctly includes entities to whom this standard is applicable. However, in requirements the entities are not qualified as ".....that uses the Network Response method....". Appropriate adjustments to the requirements should be made throughout this standard. |
| **Response:** This comment has been addressed in the applicability section of the standard; therefore, the requirements only pertain to users of this method. | | | |
| FirstEnergy | ☑ | | MOD-001, 028, 029, and 030 should be combined into one standard to eliminate the need to reference several standards at once, eliminate duplication, and simplify the applicability sections of MOD-028, 029, and 030. |
| **Response:** The DT began with this approach but the resulting standard was very large and confusing as to what requirements a TSP had to comply with. We believe that by separating the standards to each cover a different methodology the standards will be easier to follow and enforce. | | | |
| Duke Energy | ☑ | | |
| PSC SC | ☑ | | |
| SCS | ☑ | | |

4. Are there any elements other than those currently listed in R5 that need to be updated in the power flow model for calculating TTC? If "Yes," please list the elements and explain why they need to be updated in the comments area.

**Summary Consideration:** The majority of commenters agreed that there was no need for additional elements. There were some suggestions to refine or reorganize the sub-requirements, and the drafting modified R5 so that rather than specifying that the model has to be updated for the time horizon being studied – in the revised standard there are several requirements that address the modeling requirements - one general requirement (R2), and two additional requirements. One of the new requirements specifies, in greater detail, certain data that must be brought up to date in the model used for determining TTC for the intra-day and next-day time periods (R3); and another requirement for data that must be updated for determining TTC for time periods beyond the next day (R4).

| **Question #4** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | The requirements in R5 have already been mandated, correctly, in the FAC and other MOD models. To repeat those requirements in this standard will confuse the industry and make it impossible the maintain a workable compliance program for several standards. |
| **Response:** The requirements related to determining TTC for use in ATC will now be solely located within the MOD standards and the FAC-012 and FAC-013 standards will be retired. | | | |
| Entergy | | ☑ | If intent of R5.4 and R5.5 is to update power flow models to include all known outages, R5.6 and R5.7 should be merged with R 5.4 and R5.5 to include planned and unplanned outages. |
| **Response:** The DT modified the standard so that the intent of requirements R5.4 and R5.5 have been merged as suggested. In the revised standard, the merged requirement is organized by 'time period' and appears in R3.1.1, R3.2.1, R4.1.1 and R4.2.1.<br>Because 'unplanned outages' (identified in the posted version of the standard as R5.4 and R5.5) can't be predicted, these were removed from the revised standard. | | | |
| FirstEnergy | | ☑ | R 5.11 requires inclusion of the data provided by adjacent Transmission Service Providers and any other TSP with which coordination agreements have been executed; however, this standard does not include a requirement for adjacent TSPs to provide this data nor for executing coordination agreements with other TSPs. |
| **Response:** The requirement already exists in MOD-001, which is the 'parent' to this standard. This was intentionally left somewhat open because NERC cannot force coordination agreements to occur. We want to enforce that to the extent they are in place, that data MUST be utilized. | | | |
| IRC<br>IESO | ☑ | ☑ | While the component list appears to be complete, we find it difficult to keep track of or understand the rationale behind putting this requirement in this standard, while being uncertain of what changes are to be made to FAC-012 and -013. If those parts of FAC-012 and -013 that relate to TTC calculation are to be absorbed in this standard, then we'd think that having R5 (and R6) alone may not be |

| Question #4 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | sufficient. On the other hand, if FAC-012 and -013 are to remain as is or be moved to other standards, then we do not see the need to replicate partical requirements in MOD-028.<br>Note that the supplementarty SAR indicates that: "Specifically, the following Standards may be modified, transferred to NAESB or retired:<br>FAC-012 Transfer Capability Methodology<br>FAC-013 Establish and Communicate Transfer Capabilities<br>The SDT needs to be more specific and certain of its direction on these two standards to help the industry better understand and track changes. |
| **Response:** The requirements related to determining TTC for use in ATC will now be solely located within the MOD standards and the FAC-012 and FAC-013 standards will be retired. | | | |
| ERCOT | ☑ | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** Please see the response to IRC's comments. | | | |
| MEC Trading | ☑ | | A consistent way of modeling all of the things listed in R5 should be clearly identified within the standard (partial path reservations, conditional firm service, outages that last 1 day for a monthly model, etc.) |
| **Response:** The drafting team has added detail to clarify where possible. Please see the Summary Consideration. | | | |
| HQT | | ☑ | |
| Duke Energy | | ☑ | |
| ISO NE | | ☑ | |
| MEC | | ☑ | |
| MRO | | ☑ | |
| NPCC WG | | ☑ | |
| PSC SC | | ☑ | |
| SCS | | ☑ | |
| SERC ATCWG | | ☑ | |

5. In R12, we provided a preliminary response to Order 890s paragraph 245, which deals with reservations that have the same POR (generator) but different PODs (loads). Do you agree that R12 meets the intent of order 890? If "No," please suggest how you believe the Order's requirements from paragraph 245 should be addressed in the comments area.

**Summary Consideration:** The drafting team received very few comments in response to this question, and there was no consensus amongst those who did comment. The Drafting Team discussed this issue in an attempt to define specific requirements to ensure consistent implementation. Several different approaches were discussed. However, talking through examples, it was determined that each implementation would have a detrimental impact on either reliability or Open Access. Therefore, this requirement has been removed. This shall serve as a singe response to all opinions offered.

| Question #5 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | The statement as written will impair the operational flexibility of the BES. Any path or network or flowgate that has a rating higher at its POR than the rating of a generator connected at the same POR would limit the transfers at that POR to the generator size. The SDT does not want that. The only time this will be appropriate is when the generator is connected by a radial generator-tie and no other transaction from the system will use this node as the POR. |
| Duke Energy | | ☑ | The Transmission Service Provider shall limit the modeling of all Transmission Reservations from a specific generating plant to not exceed the modeled rating of all generators at that plant. Transmission Reservations should be allocated first to DNR's and the remainder allocated proportionately up to the modeled plant rating. |
| Entergy | | ☑ | The language of R12 does not directly address the intent of Order 890 paragraph 245. It does not provide clear instructions for treatment of multiple reservation from a POR (generator) other than limiting the impact to name plate rating. We suggest that a uniform method, or alternate methods be included for treating these reservations to address Order 890 paragraph 245. |
| SCS | | ☑ | We interpret the intent of paragraph 245 to imply that a generator should not be modeled at a level exceeding its maximum capability. With this interpretation, service could be granted up to the capability of the generator for each different POD. This is not allowed as R12 is currently drafted. |
| ERCOT | ☑ | ☑ | See IRC comments submitted by Charles Yeung. |
| MEC | ☑ | ☑ | The words seem to meet the requirement although developing a process which meets the requirment is very difficult to do. Also, this requirement is a transmission service request evaluation process requirement and does not belong in its present form in a standard concerning ATCs calculation. Also, there are issues with implementing this requirement. When there are numerous point to point requests for transmission service where some of them are partial path requests, it is not clear how to enforce the impacts of all transmission service shall not exceed the source at a particular point. If the Standards Drafting Team intends to continue with this requirement, the Standards Drafting Team should outline some subrequirements which explain how the Transmission Service Provider is to do this. It would be helpful if the SDT would develop an example of multiple requests some of which are partial path requests and show how the Transmission Service Provider than reviews the impacts to |

| Question #5 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | meet the requirement. |
| MRO | ☑ | ☑ | The words seem to meet the requirement although developing a process which meets the requirment is very difficult to do. Also, this requirement is a transmission service request evaluation process requirement and does not belong in its present form in a standard concerning ATCs calculation. Also, there are issues with implementing this requirement. When there are numerous point to point requests for transmission service where some of them are partial path requests, it is not clear how to enforce the impacts of all transmission service shall not exceed the source at a particular point. If the Standards Drafting Team intends to continue with this requirement, the Standards Drafting Team should outline some subrequirements which explain how the Transmission Service Provider is to do this. It would be helpful if the SDT would develop an example of multiple requests some of which are partial path requests and show how the Transmission Service Provider than reviews the impacts to meet the requirement. |
| FirstEnergy | ☑ | | However, the phrase "not exceed" can be replaced with the word "the" since the term "limiting the total impact" is synonomous. |
| MEC Trading | ☑ | | The words seem to meet the requirement although developing a process which meets the requirment is very difficult to do. This appears to make unit specific service of less value then service that lists a control area for redirecting that service. |
| PSC SC | ☑ | | |

6. Do you agree with the requirements included in the proposed standard? If "No," please list the requirements you do not agree with and explain why in the comments area.

**Summary Consideration:** Requirements related to TTC as they relate to ATC calculations have been incorporated in MOD-028, MOD-029 and MOD-030 and FAC-012 and FAC-013 will be retired. The drafting team is transferring all requirements dealing with public posting to NAESB. Changes were made to the standard to address the remaining comments.

| Question #6 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| APPA | | ☑ | Requirements R1 through R9 should be in the FAC series Standards. The TTC Standards do not address any of the reliability issues that would have been address in FAC-012 and FAC-013, if they had not been written as a fill-in-the-blank standard. The Regional Procedures for determining TTC that are requested in the existing FAC-012 would not have been written as proposed in MOD-028, 029, or 030. |
| **Response:** Requirements related to TTC as they relate to ATC calculations have been incorporated in MOD-028, MOD-029 and MOD-030 and FAC-012 and FAC-013 will be retired. | | | |
| BPA | | ☑ | R2. -- For system security reasons, the contingency list details should not be publicly available. Identifying the most critical contingencies publicly could make them a target and thus reduce system reliability. This information should only be shared with those entities demonstrably impacted by such limiting contingencies. |
| **Response:** The drafting team has been working cooperatively with NAESB and all requirements dealing with public communication will be addressed by NAESB business practices. | | | |
| Duke Energy | | ☑ | R2, R3, R8 and R16 are "communications" in nature and should be removed from NERC requirements and should be put into NAESB business practice standards where the communications requirements can be justified.<br><br>Need to re-word the following requirements:<br>R4. The Planning Coordinator, Reliability Coordinator or Transmission Service Provider shall ensure that the Total Transfer Capability (TTC) for each of its Transmission Service Provider's POR to POD Paths is calculated and up-to-date for use within the Transfer Capability time horizons spedified in MOD-001 R2.<br><br>R5. Prior to calculating TTC, the Planning Coordinator, Reliability Coordinator or Transmission Service Provider shall ensure the following components of the base case power flow model used to calculate TTC for the time horizon being studied are updated:<br>R5.6. Unplanned transmission system Element outages, or unplanned returned to service.<br>R5.7. Unplanned generation resource outages, or unplanned returned to service.<br>R5.10. Appropriate Firm Transmission Service Reservations, to eliminate netting of flows to avoid reliability concerns with associated reservations not being scheduled. |

| Question #6 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | R6. The Planning Coordinator, Reliability Coordinator or Transmission Service Provider shall follow these steps in determining the TTC for each path specified:<br>R7. Each Planning Coordinator and Reliability Coordinator that calculates TTC shall provide its Transmission Service Provider with the TTC for each of the specified paths. |

**Response:**

R2, R3, R8, R16 - The drafting team has been working cooperatively with NAESB and all requirements dealing with public communication will be addressed by NAESB business practices.

R4 - which required the Planning Coordinator and Reliability Coordinator to ensure that TTC for each of the Transmission Service Provider's paths was calculated according to a schedule has been deleted. In the revised standard, the drafting team uses the term, 'Posted Path' rather than referring to the paths as 'POR to POD Paths'. The revised standard assigns the Transmission Operator the responsibility for calculating TTC (R6) at specified intervals unless otherwise requested by the Transmission Service Provider – this supports the intent of your suggestion.

R5 – the requirement was reassigned so that it applies only to the Transmission Operator and the requirement was subdivided into several requirements with a greater focus on the data updates that are needed for calculating TTC for different time periods – the modeling updates required for calculating TTC for for intra-day and next-day periods differ from the modeling updates required for calculating TTC for use during time periods beyond the next day. This supports the intent of your suggestion.

R5 and R7 – the suggestions to add the Transmission Service Provider to the list of functional entities responsible for calculating TTC was not adopted. The drafting team modified this standard, based on stakeholder comments and a more thorough review of the Functional Model, and determined that the Transmission Operator should be responsible for calculating TTC.

R5.6 – the suggestion to enhance the requirements for modeling 'unplanned outages' was not adopted as proposed – modeling 'unplanned outages' is problematic in certain time periods – instead the drafting team merged the language from R5.4 through R5.7 which addressed various types of generation and transmission outages into a single sub-requirement that says, " Expected generation and transmission outages, additions, and retirements' This set of changes supports the intent of your suggestion.

R7 – the suggestion to qualify the subset of Transmission Planners and Reliability Coordinators that must provide the Transmission Service Provider with TTCs was not adopted because the responsibility for determining TTCs has been assigned to the Transmission Operator and the applicability section of the standard already states that the requirements in the standar are only applicable to those Transmission Operators who use the Area Interchange Methodology to calculate TTCs for Posted Paths.

| Question #6 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | |
| Entergy | | ☑ | From R5.11, language "with which coordination agreements have been executed" should be struck.<br>In R6.3, "interfaces" should be changed to ties/interconnections.<br>In R7, "each of the specified' should be struck and "idenfied in R3" should be added after paths.<br>From R11.5, the language "five years or longer in duration…..renewal" should be struck and "as applicable" be added after contracts. |
| **Response:** The drafting team did not understand why the language in 5.11 should be modified – the drafting team did add a qualifying phrase (provided that data can be associated with Facilities that are explicitly represented in the Transmission model) to clarify the reason why this data is needed<br><br>The drafting team modified the 'process' (R6) that is used to calculate TTC and the sub-requirement R6.3 was modified as follows (R7 in the revised standard) using the suggested word, 'ties' rather than 'ties/interconnections':<br><br>- The sum of the incremental Transfer Capability and the impacts of Firm Transmission Service that were included in the study model, or<br><br>- The sum of Facility Ratings of all ties comprising the Posted Path.<br><br>R7 – the drafting team modified this requirement so that it is assigned to the Transmission Operator and links with the other 'ATC-related' standards by referencing 'Posted Paths.'<br>R11.5 – the suggestion to remove the phrase, 'five years or longer in duration' was removed from the standard but the phrase, 'as applicable' was not added as this is ambiguous. | | | |
| ERCOT | | | See IRC comments submitted by Charles Yeung. |
| **Response:** See the response to IRC's comments. | | | |
| HQT<br>ISO NE<br>NPCC WG | | ☑ | R1: MOD-028 requires 'a list', MOD-029 requires 'a description'. The language for this requirement between these two MODs should be consistent.<br>R2: This list of contingencies could contain critical infrastructure information. The phrase "consistent with CEII policies" should be added to the end of this requirement.<br>R6.1: The intent of the text of Requirement 6.1 in MOD-028 and MOD-029 seems to be the same. If the intent is the same, the language should be the same. |
| **Response:**<br>R1 and R2 – R1 was revised and in the revised standard the contingencies and assumptions need to be identified in the Transmission Service Provider's ATCID. There are no posting requirements in the standard – the entities that receive the information are those that need the information for reliability.<br>R6.1 – while both MOD-028 and MOD-029 include a 'process' for determining TTC, the processes are different. | | | |
| IESO<br>IRC | | ☑ | We have a question on R13 with respect to the omission of CBM (see our comments under Q2). Further, in R15, we do not understand what would be the items that are "by the amount of capacity associated with unscheduled Transmission Service accounted for within firm and non-firm ETC" when |

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | increasing non-firm ATC. |
| **Response:** With regard to R13, FERC indicated that non-firm should not include CBM. R15 was describing the typical release of unused Firm service that will increase non-firm ATC. The algorithms added to the standard should clarify these requirements. | | | |
| SCS | | ☑ | R5.11 Comments. It may not be feasible to include all data from neighboring systems (e.g. PC or RC may not be able to incorporate all Special Protection schemes in a base case for TTC calculation). Also, the timeframes for which the values are being calculated may not allow for the incorporation of this data. |
| **Response:** The standard was revised and this requirement is now assigned to the Transmission Operator. In the revised standard, not all data needs to be updated for all time periods for which TTC must be determined. | | | |
| SERC ATCWG | | ☑ | See comments in Question 3. |
| **Response:** See response to SERC ATCWG Question 3. | | | |
| MEC | | ☑ | 1. For R1, R2, R4, R5, R6, and R7, the responsible entities described are incorrectly based upon the assumption that all NERC members are members of an RTO. These requirements should be revised in this regard to provide that "the Transmission Service Provider, the Reliability Coordinator, and/or the Planning Coordinator, as appropriate", do these requirements in the standard.<br><br>2. R6.2 and R6.3 use "first contingency" which implies that the only planning criteria to be used is first contingency outages. The TTC must be based upon the appropriate planning criteria whatever that is. The references to first contingency should be made more generic.<br><br>3. R3, R8 and other requirements that indicate that the results are to be made available publicly should indicate that these results should be made available publicly "on the OASIS" so that this information is not made publicly without registration.<br><br>4. R11 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm ETCs based on "an appropraite level of " the following inputs.<br><br>5. R14 should be expanded to include the use of metered data to forecast non-firm ETC in the operating horizon and therefore, allowing the release of non-firm ETC for non-firm ATCs in the operating horizon. This method is being used in the area to maximize the non-firm offerings in the operating horizon. I suggest wording such as the following for R18 or as a subrequirement: "Forecasts of non-firm ETC may be made using metered data so as to allow the release of non-firm ETC in the operating horizon. When such forecasting methods are used, it may be assumed that reductions in metered flows in the operating horizon are due to reductions in non-firm ETC." |
| **Response:**<br>1. The reliability entities have been modified in the standard based on stakeholder comments and a more thorough review of | | | |

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| the Functional Model. The revised standard does not assign any requirements to the Planning Coordinator or the Reliability Coordinator – but does assign responsibility for determining TTC to the Transmission Operator.<br>2. The language in R6 has been modified so that the term, 'first contingency', is not used.<br>3. The DT agrees, all publishing of information will be handled by NAESB - R<br>4. The term, 'appropriate' is ambiguous - the SDT did modify the language to be more clear. The revised standard includes an algorithm for the determination of ETC.<br>5. The revised language in the standard does not preclude the use of meter-data to increase accuracy of the calculations or the modeling. | | | |
| MRO | | ☑ | 1. The MRO believes that for R1, R2, R4, R5, R6, and R7, the responsible entities described are incorrectly based upon the assumption that all NERC members are members of an RTO. These requirements should be revised in this regard to provide that "the Transmission Service Provider, the Reliability Coordinator, and/or the Planning Coordinator, as appropriate", do these requirements in the standard. 2. R6.2 and R6.3 use "first contingency" which implies that the only planning criteria to be used is first contingency outages. The TTC must be based upon the appropriate planning criteria whatever that is. The references to first contingency should be made more generic. 3. R3, R8 and other requirements that indicate that the results are to be made available publicly should indicate that these results should be made available publicly "on the OASIS" so that this information is not made publicly without registration. 4. R11 should be revised to indicated that "The Transmission Service Provider shall determine the impact of firm ETCs based on "an approprate level of " the following inputs. 5. R14 should be expanded to include the use of metered data to forecast non-firm ETC in the operating horizon and therefore, allowing the release of non-firm ETC for non-firm ATCs in the operating horizon. This method is being used in the MRO to maximize the non-firm offerings in the operating horizon. The MRO suggests wording such as the following for R18 or as a subrequirement: "Forecasts of non-firm ETC may be made using metered data so as to allow the release of non-firm ETC in the operating horizon. When such forecasting methods are used, it may be assumed that reductions in metered flows in the operating horizon are due to reductions in non-firm ETC." |
| **Response:** 1. The reliability entities have been modified in the standard based on stakeholder comments and a more thorough review of the Functional Model. The revised standard does not assign any requirements to the Planning Coordinator or the Reliability Coordinator – but does assign responsibility for determining TTC to the Transmission Operator.<br>2. The language in R6 has been modified so that the term, 'first contingency', is not used.<br>3. The DT agrees, all publishing of information will be handled by NAESB - R<br>4. The term, 'appropriate' is ambiguous - the SDT did modify the language to be more clear. The revised standard includes an algorithm for the determination of ETC.<br>5. The revised language in the standard does not preclude the use of meter-data to increase accuracy of the calculations or the modeling. | | | |
| MEC Trading | | ☑ | This is a fill-in-the-blank standard. |
| **Response:** The revised language in the standard has attempted to eliminate the 'fill-in-the-blank' aspects that existed. | | | |

| Question #6 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| PSC SC | ☑ | | |
| FirstEnergy | ☑ | | |

7. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If "Yes," please identify the conflict in the comments area.

**Summary Consideration:** The majority of commenters did not see any conflicts.

| Question #7 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| HQT | | ☑ | We are not aware of any conflicts. However, we want to ensure that NERC recognizes that many of the requirements defined in these standards do not apply to entities that do not sell transmission service in advance of the physical flow of energy. For example, many or all items associated with firm and non-firm ETC would be zero for these markets. |
| **Response:** The DT recognizes that some of the ETC components may be zero. The applicable entities should identify and explain the zero ETC components as part of complying with the standard. Note that the standard's applicability has been modified, and the revised standard is only applicable to those Transmission Operators that use the Area Interchange Methodology to calculate TTCs for Posted Paths – and to those Transmission Service Providers that use the Area Interchange Methodology to calculate ATCs for Posted Paths. | | | |
| IESO | | ☑ | However, please note that some markets do not offer physical transmission services and hence some of the requirements in this standard do not apply to these entities. |
| **Response:** Note that the standard's applicability has been modified, and the revised standard is only applicable to those Transmission Operators that use the Area Interchange Methodology to calculate TTCs for Posted Paths – and to those Transmission Service Providers that use the Area Interchange Methodology to calculate ATCs for Posted Paths. | | | |
| IRC | | ☑ | No, but please note that some markets do not offer physical transmission services and hence some of the requirements in this standard do not apply to these entities. |
| **Response:** Note that the standard's applicability has been modified, and the revised standard is only applicable to those Transmission Operators that use the Area Interchange Methodology to calculate TTCs for Posted Paths – and to those Transmission Service Providers that use the Area Interchange Methodology to calculate ATCs for Posted Paths. | | | |
| ERCOT | | ☑ | See IRC comments submitted by Charles Yeung. |
| **Response:** Please see the response to IRC's comments. | | | |
| ISO NE | | ☑ | We are not aware of any conflicts. However, we want to ensure that NERC recognizes that many of the services (e.g., the offering of firm point to point service, see R.11.4) to which these requirements apply are not offered by Transmission Service Providers that do not sell transmission service in advance of the physical flow of energy.For example, many or all items associated with firm and non-firm ETC would be zero in the markets administered by these TSPs. For example, over the Pool Transmission Facilities in New England, all capability is considered available to the market (i.e., the Total Transfer Capability) until real-time scheduling occurs. With the current arrangement of these proposed standards, the ATC Implementation Document would clearly document how the TSP complies with these standards, based on what services are offered through the Commission-approved tariff and/or market rules. |
| **Response:** The DT recognizes that some of the ETC components may be zero. The applicable entities should identify and | | | |

| Question #7 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| explain the zero ETC components as part of complying with the standard. Note that the standard's applicability has been modified, and the revised standard is only applicable to those Transmission Operators that use the Area Interchange Methodology to calculate TTCs for Posted Paths – and to those Transmission Service Providers that use the Area Interchange Methodology to calculate ATCs for Posted Paths. | | | |
| NPCC WG | | ☑ | We are not aware of any conflicts. However, we want to ensure that NERC recognizes that many of the requirements defined in these standards do not apply to entities that do not sell transmission service in advance of the physical flow of energy. For example, many or all items associated with firm and non-firm ETC would be zero for these markets. |
| **Response:** Note that the standard's applicability has been modified, and the revised standard is only applicable to those Transmission Operators that use the Area Interchange Methodology to calculate TTCs for Posted Paths – and to those Transmission Service Providers that use the Area Interchange Methodology to calculate ATCs for Posted Paths. | | | |
| MEC | | ☑ | |
| Duke Energy | | ☑ | |
| Entergy | | ☑ | |
| FirstEnergy | | ☑ | |
| MRO | | ☑ | |
| PSC SC | | ☑ | |
| APPA | ☑ | | See comment No. 1 |
| **Response:** See APPA response to comment No. 1. | | | |
| MEC Trading | ☑ | | No requirement for consistency |
| **Response:** The drafting team feels there are requirements for consistency in calculating ATC and TTC in the revised set of standards. | | | |
| SCS | ☑ | | R12 requires the TSP to limit the total impact of all Transmission Service from a "POR" (multiple generators) not a specific "generator" as written in Order 890. |
| **Response:** This requirement has been removed, see Summary Consideration of Question 5. | | | |

8. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard MOD-028-1.

**Summary Consideration:** The SDT agrees with the comment regarding "Posted Path," and has changed the standards accordingly. The DT uses the term "post-backs" and it is expected that NAESB will defined the details of what is included in postbacks. Additionally, all aspects of publishing information have been removed from these standards and will be handled by NAESB.

| Question #8 | |
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| **Commenter** | **Comment** |
| APPA | MOD-028 is very confusing and it will be difficult, if not impossible, to integrate into a Compliance program. The Compliance Monitor and the industry will have a very difficult time determining what needs to be accomplished to be compliant.<br>All of the Documents in this review have been written like a policy and this will not permit a Compliance Monitor to be able to determine if the Registered Applicable Function is conducting themselves in a manner that will meet the objectives of the Standards. |
| **Response:** The language of the standards has been revised such that the requirements are measurable. | |
| BPA | The ATC MODs (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) do not clearly distinguish the methodologies and their applications. Please provide narrative descriptions of these methodologies.<br>The Applicability section 4.1. through 4.3. and R1., R3., R6. through R10., R13., and R16. should be clarified that ATC need only be calculated and posted for Posted Paths, where "Posted Path" is defined consistent with NAESB R-4005 and Order 889, RM95-9-000, April 24, 1996, P. 58-60.<br>R11.7. and R14.6. -- Please define the term "Post-back". |
| **Response:** The drafting team revised each of the standards to improve their clarity.<br><br>The drafting team has adopted the term, 'Posted Path' as proposed and will post it with the revised standard.<br><br>The SDT modified the set of ATC standards to use the term, "Posted Path," throughout to improve consistency and clarity.<br><br>The DT uses the term "post-backs" and it is expected that NAESB will defined the details of what is included in postbacks. | |
| ERCOT | ERCOT is a separate Interconnection and Region connected to the Eastern Interconnection through DC ties. Texas Senate Bill 7 effective on 9/1/99 amended the Texas utilities code to provide for the restructuring of the electric utility industry within the ERCOT Interconnection. The act deregulated the electricity generation market to allow for competition in the retail sale of electricity. As of July 2001 the ERCOT interconnection began operation as a single |

| Question #8 | |
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| **Commenter** | **Comment** |
| | Balancing Authority Interconnection and implemented a market in accordance with the Texas Public Utility commission ruling. Since the implementation of this Act, all of ERCOT has been a single Balancing Authority Area and there has been no reservation of transmission capacity in ERCOT.<br><br>Available Transfer Capability is defined as the measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin. The ERCOT Interconnection has already moved “beyond” ATC and into a Market design which resulted in the disappearance of an explicit transmission service product. In addition the DC Tie transfer capability is planned and coordinated by a TSP that is a member of both Regions and therefore both ERCOT and SPP are notified when the DC Tie capability is reduced.<br><br>Under ERCOT market rules, Transmission Service allows all eligible transmission service customers to deliver energy from resources to serve load obligations, using the transmission facilities of all of the Transmission Service Providers in ERCOT. Currently ERCOT employs a zonal congestion management scheme that is flow-based, whereby the ERCOT transmission grid, including attached generation resources and load, are divided into a predetermined number of congestion zones. This congestion management scheme applies zonal shift factors, determined by ERCOT, to predict potential congestion under the known topology of the ERCOT System. This scheme is used in the Day Ahead and Adjustment Periods to evaluate potential congestion. During the operating period ERCOT uses zonal shift factors to determine zonal Redispatch deployments needed to maintain flows within zonal limits. The local congestion management scheme relies on a more detailed Operational Model to determine how each particular Resource or Load impacts the transmission system. This model uses the current known topology of the transmission system. Unit specific Redispatch instructions are then issued to manage local congestion.<br><br>In the future ERCOT will be transitioning from a Zonal Market to a full LMP market. This system is designed to manage congestion in the Day Ahead and Real-Time on a Resource specific basis. Under both of these market designs transmission facility limits are established in advance and updated based on coordinated exchange of information between transmission providers and ERCOT in planning and operating periods.<br><br>In the current and future ERCOT market design the method of calculating ATC, TTC and the use of CBM and TRM are not applicable to the ERCOT Region. ERCOT does not have a synchronous connection with any other Balancing Authority Area, and does not use the transmission reservation and scheduling practices addressed by these standards. ERCOT requests the drafting team consider revising the wording so that Responsible Entitles required to conform to the standards are those that are synchronously connected with other Balancing Authority Areas and/or offer transmission reservations and schedules within the interconnection. We also recommend that the standard allow for ERCOT exception or exemption from calculation and posting of ATC, TTC, CBM, and TRM without the need for a Regional variance. |
| **Response:** The SDT agrees that this is a concern – ERCOT may wish to submit a request for a Regional Difference. | |
| FirstEnergy | The standard should include specifics of methods for complying with the term "publicly available" such as posting on OASIS, a corporate web page, etc. (This concept is mentioned in all MOD-028, MOD-029, and MOD-030.) |

| Question #8 | |
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| **Commenter** | **Comment** |
| | R5.10 needs more clarity. While it provides leeway with respect to recognizing Firm Reservations, the term appropriate is subjective in nature and requires quidance on determing what is appropriate and what is not. |
| **Response:** All aspects of publishing information have been removed from these standards and will be handled by NAESB. The DT agrees with the comment on 5.10 and has modified the standard accordingly – see the list of information the Transmission Service Provider must include in its Area Interchange Capability Implementation Document in the revised standard. The list of information that must be in that ATCID has been modified to include contractual obligations for allocation f TTC (R1.3). | |
| IESO<br>IRC | Please see our comments on the Supplementary SAR. Also, as indicated under Q4, we are concerned with the lack of details and specific direction on treatment of FAC-012 and -013, and how changes to these two standards will be coordinated with the requirements in this standard (and MOD-029 and MOD-030). |
| **Response:** The DT addressed this concern in the response to comments on the supplemental SAR. Many stakeholders indicated that the standards needed more specificity and the drafting team has made significant changes to all of the standards in this set to improve consistency and clarity. | |
| MEC | The purpose of each of the standards should be revised to be more in-line with each other, that is some refer to "transparent" and others do not. The purpose in MOD-028-1 be revised to replace "uniform" with "transparent". |
| **Response:** The DT modified all of the purpose statements in MOD-028, MDO-029 and MOD-030 to use the phrase, 'consistency and transparency'. The Purpose of MOD-028 was changed to: To increase consistency and transparency in the development and documentation of transfer capability calculations for short-term Transmission services performed by entities using the Area Interchange Methodology to support reliable system operations. | |
| MEC Trading | This standard should be combined with MOD-30 and the requirements should be written to require consistency. |
| **Response:** The DT disagrees. There is sufficient difference between the two methods to warrant separate standards. | |
| MRO | The purpose of each of the standards should be revised to be more in-line with each other, that is some refer to "transparent" and others do not. The MRO recommends that the purpose in MOD-028-1 be revised to replace "uniform" with "transparent". |
| **Response:** The DT modified all of the purpose statements in MOD-028, MDO-029 and MOD-030 to use the phrase, 'consistency and transparency'. The Purpose of MOD-028 was changed to: To increase consistency and transparency in the development and documentation of transfer capability calculations for short-term Transmission services performed by entities using the Area Interchange Methodology to support reliable system operations. | |
| SCS | 1. As drafted, it is not completely clear as to which of the requirements would apply to long-term planning and which requirements would not apply.<br>2. The group should consider how conditional firm will be treated with respect to ETC and the TTC calculation.<br>3. The reference in R12 to "nameplate" should be change to "maximum capability." Under certain conditions, the output of a generator can exceed the value of its nameplate. |
| **Response:** MOD-028 as drafted does not apply to long-term planning. Language was added to the standard (R4.1) to clarify that the calculations of TTC are for time periods through 13 months. The evaluation of long-term service requests is | |

| Question #8 | |
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| **Commenter** | **Comment** |
| addressed very prescriptively in each TSPs OATT; therefore to avoid any potential conflict MOD-028 only pertains to short-term transmission service requests. Additionally, as mandated by FERC Order 890, it is expected that long-term service requests be evaluated by the same criteria that a transmission owners use to plan their respective system.<br><br>Conditional Firm Service (hours based) should be treated as Firm ETC except in the time frames (horizons) that curtailment is probable. Conditional Firm Service (contingency based) should be treated as Firm ETC for all horizons; however, operationally it is expected that RCs will develop processes to curtail this service when the limiting contingency occurs. NAESB should develop business practices for the conversion of both types of long-term Conditional Firm Service(CFS) when sufficient short-term ATC is available to make all or a portion of the CFS service firm as described in FERC Order 890.<br><br>R12 has been removed from the Standard | |
| SERC ATCWG | Standard is not clear as to what applies to long-term timeframe and short-term timeframe.<br>Reference in R12 to generator nameplate should be changed to maximum capability since in some conditions the generator can exceed nameplate rating. |
| **Response:** The standard applies only to the short-term service horizon. Language was added to the standard (R4.1) to clarify that the calculations of TTC are for time periods through 13 months.<br>R12 has been removed from the Standard. | |