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MEMORANDUM TO: The Commission

FROM : Interconnection Study Team
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SUBJECT : Options for Addressing Generator Interconnections in the Interim and the Longer Term

The attached memo offers a variety of options for addressing issues concerning generator interconnection. However, since completing the memo and observing recent Commission meetings, the Study Team has come to the conclusion that it is both feasible and desirable for the Commission to move ahead more quickly than originally contemplated to put in place a standard interconnection agreement and procedures for all public utilities and RTOs nationwide. The Study Team now recommends that the Commission adopt the following two-step approach:

1. <u>Issue a short turn-around NOPR to address contract and product issues.</u>

In Step 1, the Commission would propose a modified version of the ERCOT standard generation interconnection agreement and procedures for interested parties to use as a "straw man" in creating a final standard interconnection agreement and procedures. The NOPR would propose standard interconnection studies and resulting rights, such as establishing a minimum interconnection standard and defining standard interconnection products. To expedite the process, the NOPR should state that any proposed modifications that benefit only a single entity rather than the market as a whole will be rejected. The Study Team believes the short turn-around NOPR could result in a final rule within 120 days. The rule would apply nationwide; however, the Commission may entertain requests by RTOs/ISOs to propose modifications that reflect regional practice and benefit the market.

2. <u>Issue a NOPR that addresses issues of cost responsibility</u>.

In Step 2, the Commission would issue a second NOPR (or perhaps a second phase of the Step 1 NOPR) that would address the assignment of responsibility for

> the cost of interconnections and associated system upgrades. The proposed rules would consider the effect of various cost responsibility rules on the incentives of generators and transmission providers to facilitate interconnections and to make efficient investment decisions. The proposed rules would be written with reference to the specific interconnection products identified in Step 1, including any products that are unique to RTOs/ISOs. The proposed rules could be issued contemporaneously with the Step 1 NOPR, or they could be issued upon promulgation of the final rule of Step 1. The goal would be to complete the process approximately nine months after issuing the Step 2 proposed rules.

If adopted, this two-step approach would quickly put in place standard procedures and an interconnection agreement that would expedite the interconnection process and level the playing field nationwide, while allowing extra time to resolve the more contentious issues of cost responsibility.

GENERATION INTERCONNECTION OPTIONS

Do we need standard procedures for interconnection for electric utilities?

Yes. Interconnection is a critical aspect of open access transmission service and standard interconnection procedures are essential for providing the right incentives for both transmission providers and generators.[1] We need to have interconnection procedures that will encourage needed investment in infrastructure, remove incentives for transmission providers to favor their own generation, and ease entry for competitors while ensuring efficient siting decisions.

What have we done so far?

Order No. 888 sets forth our open access principles as they apply to transmission service. However, it does not directly address generator interconnections, which are implicitly included as a part of transmission service. The Commission, in Tennessee Power Company (Tennessee), 90 FERC ¶ 61,238 (2000), clarified that interconnection is an element of transmission service, that *customers have the right to request interconnection separately from the delivery component of transmission service,* and that interconnection must be offered under the terms of the *pro forma* tariff. This includes the right of the customer to request the transmission provider to file an unexecuted interconnection agreement if a dispute cannot be quickly resolved.[2] Tennessee led the Commission to encourage, but not require, transmission providers to revise their open access tariffs to include specific interconnection procedures including standard interconnection agreements and specific criteria, procedures, milestones and time lines for evaluating interconnection requests.[3] A number of public utilities with facilities covering a large portion of the nation's grid have filed or have committed to file these now somewhat uniform set of interconnection procedures for the facilities under their control, including all of the ISOs.

Is there remaining dissatisfaction with existing interconnection procedures?

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[1] See Attachment A for a definition of interconnection service.

[2] See, *e.g.*, American Electric Power Service Corporation, 91 FERC ¶ 61,308 (2000) and Commonwealth Edison Company *et al.*, 92 FERC ¶ 61,018 (2000).

[3] See, *e.g.*, Commonwealth Edison Company *et al.*, 91 FERC ¶ 61,083 (2000).

Yes. From our outreach efforts we have found that there is some measure of discontent and uncertainty surrounding critical elements of interconnection in terms of unnecessary delays and possible discrimination, insufficient incentives and commitments, confusion about what rights come with interconnection and uncertain cost responsibility. This results in less investment in infrastructure and less confidence in the competitiveness of the markets. Through pleadings, complaints, informal conversations, staff has found that:

Merchant generators see

- difficulty in securing interconnection without requesting delivery;
- noncomparable treatment to the transmission provider's own generation or additions;
- system upgrade costs as unrelated and, therefore, oppose payment;
- delays and uncertainty inherent in the process due to the *pro forma* tariff's lack of binding commitments and firm deadlines; and
- lack of transparency of transmission information needed to make an independent assessment of the impact of an interconnection request.

Transmission providers want

- minimum commitments from generators seeking to interconnect prior to performing studies to weed out those who will likely never interconnect, resulting in a more manageable and realistic queue;
- assurance that their control area will benefit from, or at least not be burdened by, adding generators, particularly when the new generator seeks to locate on one system but serve load on another; and
- improved communication, or information, between the generators and the loads they serve.

In sum, numerous issues remain to be resolved, among them: (1) the extent to which we should standardize interconnection procedures, *i.e.* whether we should require all utilities to revise their transmission tariffs to include interconnection procedures; (2) to what extent these procedures need to be generic or identical; (3) how to ensure accurate interconnection studies are produced in a timely fashion; (4) the extent to which transmission data necessary for interconnection should be made transparent; (5) how to create the proper incentives for transmission providers to treat all generation comparably; (6) how to balance the costs and benefits of siting generation both with respect to exports and over building transmission or generation; and (7) who should pay for the costs of system upgrades associated with interconnection, including the issue of whether the generator should be required to act initially as a banker and finance the cost of systems upgrades associated with interconnection.

What objectives must we consider when developing an interconnection policy?

The electric industry is faced with the competing need for additional generation and transmission infrastructure and efficient price and, therefore, siting signals. Any efficiency concerns must include careful consideration of cost responsibility for system upgrades necessary to interconnect the new generator. Assign too little of the cost responsibility to the generator and it has no incentive to site in a location that may reduce congestion on the grid. Assign too much and the generator finds it uneconomic and the unit is never built.

The industry also needs to have confidence in the marketplace. This comes in the form of clear market rules and reducing barriers to entry, including eliminating incentives for transmission providers to favor their own generation. Such discussions naturally include the role RTOs have in keeping separate control of the transmission grid from generation owners. RTOs also have a role in distributing and balancing the costs and benefits of generators siting in one control area for the purpose of selling in a neighboring control area, and they offer independent studies and information on a regional, rather than single system, scale.

Can we just adopt our natural gas pipeline interconnection policy?

Not necessarily. The gas and electric industries operate under different standards with respect to interconnection. Pipelines have no requirement to expand to meet increasing demand. On this basis, the Commission adopted its current interconnection policy in <u>Panhandle Eastern Pipe Line Co.</u>, 91 FERC ¶ 61,037 (2000), (<u>Panhandle</u>). The policy announced in <u>Panhandle</u> enables a party desiring access to a pipeline to obtain an interconnection if it satisfies five conditions. First, the customer must be willing to bear the costs of the construction. Second, the proposed interconnection must not adversely affect the pipeline's operations. Third, the proposed interconnection and any resulting transportation must not diminish service to the pipeline's existing customers. Fourth, the proposed interconnection must not cause the pipeline to be in violation of any applicable environmental or safety laws or regulations with respect to the facilities required to establish an interconnection with the pipeline's existing facilities. Finally, the proposed interconnection must not cause the pipeline to be in violation of its right-of-way agreements or any other contractual obligations.

This policy does not require a pipeline to expand its facilities. Conversely, a public utility is required to expand its system to accommodate requests for new or additional service. Thus, the Commission must take into consideration this obligation when deciding its interconnection policy for electric utilities.

Is it possible that the Commission could adopt procedures already in place in ERCOT?

Again, not necessarily. In Texas, the state commission worked with the state's utilities to craft a standard set of interconnection procedures including a standard interconnection agreement. The goal there was to insure single system planning and efficiency, eliminate delays in the interconnection process, and to remove incentives for the transmission providers to favor their own generation. The procedures included specified deadlines for completion of facilities by the transmission provider and commencement of operations of the generator, coupled with termination rights by either side for the other not meeting its deadlines. The standard interconnection agreement covered a large number of standard terms and conditions.

All of these goals and means are consistent with where this Commission would want to be on interconnection; however, there are significant structural differences between Texas and the rest of the nation. First of all, both in terms of jurisdiction and operational control, Texas/ERCOT has complete control--there is no competing jurisdiction, and the ERCOT ISO performs and integrates all of the transmission and generation planning alternatives, carefully balancing the needs of both. Also, there's no issue of overbuilding in ERCOT for export to another region, as ERCOT is practically an electrical island. In one sense, ERCOT is in an ideal position for an RTO–it has full control of the grid and of generation additions, no seams issues, and no multi-state or state-federal jurisdictional concerns to satisfy. Accordingly, any use of the ERCOT interconnection procedures would require adaptation to recognize the aforementioned structural differences.

What can the Commission do right now to begin to address interconnection?

Because of their independence from market participants, the RTOs will certainly be equipped to handle interconnection in a non-discriminatory fashion. However, actual initial operation dates for all of the RTOs remain in question. Given that the Commission may want to act quickly and accomplish something tangible in the very short term, the Commission could:

> **Option**: *Issue an order that requires the remaining public utilities to file proposed standard interconnection procedures consistent with those approved for other utilities, and resolve any remaining issues through further Commission orders.*

Since the Commission began encouraging utilities to file standard interconnection procedures, many utilities have filed or have committed to file such procedures. While we have not ordered a generic set of procedures, our orders have, over time, resolved disputes by consistently modifying proposals to conform with previously approved filings. Most customers wanting to interconnect were able to successfully negotiate mutually acceptable interconnection agreements under these now standardized procedures. During the period (September 2000-July 2001), only 17 out of 190 filed interconnection agreements necessitated Commission, rather than delegated, action. This means 91% of the filed interconnection agreements were resolved by the parties and, therefore, the interconnection procedures already in place have been fairly effective.

The Commission could issue an instant final rule requiring the remaining utilities to modify their open access tariffs to specify interconnection procedures that will apply to all interconnections on that system. This would modify our current position of encouraging transmission providers to file interconnection procedures to one requiring such filings by all who have yet to file. This will level the playing field across the country immediately. If necessary, the Commission could later examine whether any inconsistencies between transmission providers' standard procedures need to be eliminated.

Are there other, medium term actions the Commission may want to take?

Yes. The Commission could choose to address certain discrete issues that could make a substantial difference in building infrastructure and strengthening the competitiveness of electric energy markets.

> **Option A**. *Issue a short turn-around NOPR to address one or more discrete issues for which immediate resolution would bring tangible benefits*

to the market. Put the final proposals in place within a few months and before most of the RTOs are operational.

Issue 1: Standardize Interconnection Studies and Resulting Delivery Rights. Much of the dissatisfaction regarding delay in getting interconnected relates to the uncertainty that results from transmission providers performing different studies for interconnection. Some transmission providers perform studies assuming generators would be network resource-ready while others simply study whether interconnection will trip any protective devices.[4]

Option A1-1: Establish a minimum interconnection standard. PJM and NYISO determine the minimum upgrades needed for interconnection using a reliability test: if the system impact study identifies a reliability impact from the new generator which can be managed through normal operating procedures including economic redispatch of existing units, then no upgrade will be required. Redispatch was contemplated in Order No. 888, but was not included in the pro forma tariff. This approach will require a tariff provision. This approach is appropriate in a market environment where competition should determine dispatch order. Also, it does not assume that existing generators have higher priority rights to existing transmission capacity. Any additional service would be required as part of the delivery component of transmission service.

Option A1-2: Define a single interconnection product. Tennessee greatly benefitted generators by clearly separating requests for interconnection from having to also request transmission service and identify a particular delivery point. However, to some generators, it also created a problem in that they were unable to request an interconnection which would provide some measure of certainty with respect to deliveries within the transmission provider's control area.

[4] There has been some confusion as to what constitutes interconnection rights. However, in Southern Company Services, Inc. (Southern), 95 FERC ¶ 61,307 (2001), the Commission stated that interconnection by itself conveys no right to delivery service (*i.e.*, to move power to a delivery point). The practical effect of this "right" is that, if another generator subsequently seeks to interconnect in the same local area and the grid cannot accommodate "receipt" of power from the two generators without expansion, it is the new generator that must pay for the expansion.

To address this issue (and to avoid the fight over what constitutes "minimum" interconnection facilities), we could determine that, for all interconnections, the facilities study would assume that interconnecting generator has the right to be a network resource to compete to supply the existing load (or load growth) within the transmission provider's control area without having to be designated as such by a particular load at the time interconnection is requested. This means the transmission provider will model the system assuming that the new generator will displace at least in part existing supply rather than assuming that the new generator will serve incremental load. Similar to the right of a point-to-point customer to defer commencement of service, the generator would have up to five years to find a load to serve so long as the generator pays an amount equal to 1/12 of the annual transmission charges associated with the full output of its unit. In addition, the generator should be given the option of deferring negotiation of the network operations portion of the interconnection agreement until a time nearer to when the unit will be energized. This will allow construction to begin sooner by keeping the early negotiations on the facilities needed for interconnection rather than haggling over how the new generator and transmission provider will work together upon commencement of service.

This option will remove uncertainty that results from the existence of varying assumptions inherent in facilities studies. It would also give the generator some measure of flexibility in the load it will serve, which is comparable to a transmission provider's ability to place a generator in the transmission queue for the purpose of serving future network load growth. However, while a single standardized procedure with simplified assumptions will expedite the process, there will be a trade-off. Requiring this single set of rights will result in a bit less flexibility for interconnection, since customers requesting interconnection-only may end up being required to pay for more facilities than they envisioned (to provide a higher grade service if they ultimately need something less, *e.g.* point-to-point service on a single path). In addition, some may view this option as, to some extent, mixing transmission rights with the basic interconnection service.

Option A1-3: Define multiple interconnection products. Some generators have indicated that they merely want interconnection; they don't want to wait for or pay for more extensive network facilities and rights. They state that a minimal interconnection would allow them to compete on price to gain access to the grid without the expense and duplication of additional facilities.

Instead of mandating one grade of interconnection study and ensuing rights, we could require transmission providers to offer a Level 1 and a Level 2 service. When interconnection is requested; two studies could be done at the same time. The first study would provide some measure of minimal rights, such as a stability, short circuit, and overload analysis (Level 1). This study would require the interconnecting generator to take the system as it is, meaning the generator would receive service as available. The second study would be the "network resource" study discussed in Option A1-1 above (Level 2).[5] When presented with the results of the two studies, the customer would then be required to choose which type of service it wanted within a specified time period. This would not only serve to standardize the types of studies to be performed (which removes confusion over terminology and expectations) but would also shorten processing times under circumstances where the customer was dissatisfied with one type of study and subsequently requested another more or less extensive study. The benefit of a minimal interconnection product would be that the generator could possibly gain interconnection more quickly, but would face the risk of restricted output and a lower dispatch priority. PJM currently offers two standard interconnection services, Energy Resource (as available access) and Capacity Resource (firm access to the system).

Option A1-4: Require different studies for large and small generators. In many instances, most of the usual facilities studies may not have to be performed for generators of minimal size due to the fact that their output (typically located near load centers) can be absorbed into the system within normal operating tolerances. PJM, for instance, has a separate set of interconnection procedures for units (or increases) of up to 10MW. PJM does not perform stability analyses for these additions unless existing stability margins are already small. Not performing certain studies for small generators will streamline the processing of these requests and will dramatically shorten the time to secure an interconnection without substantially altering the processing time for larger units.

Issue 2: Paying for the Network Facilities. Many disputes regarding interconnection are founded in the question of who pays for any necessary system upgrades. Our traditional pricing policy is based on the dual notion that, (1) if the facilities are sole use (*i.e.* a radial from the grid to the new generator), the facilities are paid for by the customer benefitting from them; and (2) if the facilities are network upgrades which would not be built "but for" the addition of the new customer, that customer must pay for its use of the grid based on the higher of the existing system

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[5] Of course this does not preclude parties from negotiating a mutually agreeable, non-standard agreement.

transmission rate or the cost of the necessary network upgrades.[6] The question concerning interconnection costs today has been one of should the generator pay up-front the full cost of any network upgrades, or should the transmission provider pay and, subsequently, seek to recover those costs through its transmission charge. Also to be addressed is the "generator as banker" issue, *i.e.* if the generator pays for the facilities up-front and receives a credit against any transmission charges, should the generator be compensated for the time value of money from the time the up-front payment is made until the last credit is received.

Currently, the states have a wide range of opinions on the question of who should pay for network upgrades including assigning the costs to the transmission provider, the generator, or some form of cost sharing between market participants.

Option A2-1: Require generators to pay up-front all costs to interconnect, including network upgrades. To the extent the generator is required to pay up-front costs of the facilities, this option has the benefit of incenting generators to avoid extensive network upgrades and instead site their facilities in a location that is nearer to load and, therefore, more beneficial to the host system. This option also has the potential benefit of speeding interconnection in that it is possible that generators may have better access to credit markets than transmission providers.[7]

Following the up-front payment, transmission providers are required to credit the up-front facilities payment against the monthly transmission charges associated with the transmission of the generator's output. However, while transmission credits repay the actual up-front payment by the generator, they do not consider the fact that the generator, by financing the cost of the facilities and only later being reimbursed, is forced to act as a bank for the transmission provider and loses the time value of the up-front payment. In a rehearing order in AEP, we refused to require the transmission provider to return the time value, reasoning that the transmission provider did not hold the money but instead immediately invested it in the construction of the necessary upgrades. Adding the time value to the credit amount leaves the generator in the same place as if the costs were fully rolled-in (*i.e.* it pays for all of the costs of the network upgrade through the transmission charge, as does all of the other transmission customers), which is the intent of the credits.

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[6] Public Service Company of Colorado, 59 FERC ¶ 61,311 (1992).

[7] See, *e.g.* Removing Obstacles, 96 FERC ¶ 61,155 (July 27, 2001), slip op. at p. 23.

Option A2-2: Require the transmission provider pay for all costs of interconnection. This would incent generators to build where they want to (*e.g.* near a pipeline or in Arizona to export to California) with less concern for siting where no network upgrades are needed, since the generator would not make an up-front payment for the facilities. As this is generator-friendly, it may result in more infrastructure. Moreover, it may eliminate one of the biggest sources of contention–the queue, where the last generator on the system faces the risk of paying for a greater amount of system upgrades. This fight extends to whether an interconnecting generator must pay for upgrades included in the transmission provider's regular system planning if such facilities are also necessary for the interconnection. If all network upgrade costs are rolled in, there is no more dispute. Conversely, this option raises the issue of inefficient siting and of how transmission providers will recover these costs if they are under a retail rate freeze. Some transmission providers have suggested that these otherwise unrecoverable costs could be placed in a regulatory asset account and recovered after the freeze.

Option A2-3: Determine who pays based on whether the siting decision benefits the market. We could resolve to take a middle ground approach and require the interconnecting generator to pay for all or a portion of any necessary system upgrade costs in instances where they have made a siting decision that is not "system friendly," *i.e.* siting on the wrong side of the constraint. This tends to reward good siting decisions, but likely will lead to fights over exactly what is a "good" siting decision.

Option B: *Rather than issuing a NOPR, the Commission could lay out some or all of the above principles in a policy statement.*

While a policy statement would not have the same impact as the Final Rule resulting from a NOPR, the Commission’s stated preferences would be on the street in final form a lot sooner and we could begin enforcing those preferences through individual interconnection orders. Alternatively, the policy statement could form the basis for industry-wide outreach and an eventual NOPR.

What kind of issues could the Commission address if it were to either follow-up one or more of the shorter-term measures with a full NOPR on interconnection?

A full blown NOPR, which could take six months or more to implement, would allow for outreach and a detailed examination and discussion of numerous issues, including:

- what should be the standard interconnection products, rights, criteria, and procedures, including standard assumptions for facilities studies (*e.g.* should the transmission provider assume that the new generator will serve incremental load, or will it displace an existing generator in whole or in part)
- what would be covered by standard interconnection procedures, including such things as: milestones, rights, queuing rules, incentives to ensure timely completion, rights/responsibilities for generators to maintain queue position, clear statement of transmission rights, information availability for customers to perform their own studies, should customers be permitted to perform their own system upgrade studies and, if so, what degree of information should the transmission provider be required to provide, etc.
- how should these standards be implemented:
    - require each utility to meet certain standards that we announce
    - the Commission writing a <u>pro</u> <u>forma</u> interconnection tariff
    - adoption of the ERCOT model for interconnection
    - decide that the standards currently in place are sufficient to ensure timely interconnections for now, but require the RTOs to propose standard procedures.
- who bears the cost responsibility for system upgrades, including the generator as banker/time value of the transmission credits issue.
- how should the Commission best encourage the addition of renewable generators to the grid
- how should jurisdiction be divided between the Commission and state commissions (*e.g.* distribution level vs. transmission level interconnections, generator size, distributed generation, etc.)

This option is our usual means of addressing major issues, would result in a thorough airing of all issues related to interconnection and likely would lead to good policy; however, it will take some time to achieve. This could be done in concert with one or more of the options noted above.

Attachment A - Defining Generator Interconnection Service

In Tennessee Power Company, (Tennessee), 90 FERC ¶ 61,238 (1990), the Commission determined that interconnection service is an element of transmission service and is required to be provided under the relevant provisions of the pro forma tariff (*e.g.*, procedures for performing studies, establishing customer responsibilities, and entering service agreements). The Commission further stated that customers have the right to request the interconnection component of transmission service separately from the delivery component.

Although to some it may seem obvious, defining the interconnection component of transmission service in a way that clearly distinguishes it from the delivery component has proven to be controversial. Even when they are not required to arrange for delivery service *per se*, generators seeking to interconnect complain that transmission providers often require upgrades that go beyond what is needed for interconnection only. Generators claim that this forces them either to pay excessive costs or face long delays while they attempt to resolve the issue.

The apparent magnitude of this problem suggests that a clear definition is needed for what, in fact, constitutes the interconnection component of transmission service. One possibility can be found in American Electric Power Service Corporation, 91 FERC ¶ 61,308 (2000), *order on reh'g*, 94 FERC ¶ 61,166 (2001) (AEP). There the Commission determined that AEP's definition of Direct Assignment Facilities (DAF) was a reasonable representation of the facilities that would not have been needed but for the customer's request for interconnection:

> (a) the facilities necessary to physically and electrically interconnect the generating facility to the Transmission System and (b) the minimum necessary local and network upgrades that would not have been required but for an Interconnection Request, including (i) system upgrades necessary to remove overloads and (ii) system upgrades necessary to remedy short circuit or stability problems resulting from the connection of the generating facility to the network. Direct Assignment Facilities shall not include system upgrades that may be required to move power from the point of interconnection to load.

The use of such a "but for" test would appear to provide a sound basis for determining what facilities are required for interconnection. However, the manner in which such a test is performed can have a significant impact on the determination of the minimum facilities required for interconnection. To illustrate, a but-for analysis typically involves a system impact study and a facilities study, beginning with a baseline analysis of the system without the new generator, followed by an analysis that includes the generator. Any upgrades that are needed to accommodate the generator above and beyond the baseline are deemed to be interconnection facilities. However, the way in which existing generating units are modeled in the baseline analysis can have a significant effect on the study results. In particular, if the analysis assumes that existing generating units will continue to be dispatched as they have been in the past, then the facilities needed to accommodate the output of the new generating unit may be considerably more extensive than they would be if the study assumed that existing generators could be redispatched in some manner.

In this regard, the modeling approach used by both PJM and the NYISO is instructive. These ISOs determine needed upgrades using a reliability test that allows for the redispatch of existing generators. Specifically, if the system impact study identifies a reliability impact from the new generator, and that impact can be managed through normal operating procedures including economic redispatch of existing units, then the impact will not be deemed to be a violation of reliability planning criteria. In today's market environment, where competition among generators should be the principal determinant of which ones will operate at any given time, this approach appears to be the correct one. To do otherwise would effectively grant priority rights to existing generators, rights that they would not be entitled to in a well functioning competitive marketplace.