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July 3, 2013

Kate Kahlert
Public Utilities Commission
121 – 7th Place East, Suite 350
St.Paul, MN 55101

RE: Rulemaking Minn. R. Chapter 7849 – Certificate of Need
Comments and proposed Radio PSA form

Dear Ms. Kahlert:

Enclosed please find my Comments based on Committee exercises thus far over the last two meetings and various proposals regarding criteria, which we'll be discussing at the next meeting. Also attached please find proposed Radio Public Service Announcement (PSA) form based on my years of experience as Grand Pooh-Bah of PSAs at KFAI 90.3 Fresh Air Radio several past lives ago.

<u>ISSUES OF PUBLIC PARTICIPATION AND TRANSPARENCY</u>

I appreciate your consideration of a public opportunity for comment at some point in the committee meeting, a necessary provision that I hope is adopted. However, I want to be clear that my joy at this opening for the public is not an endorsement of the limited allocation of seats for the public.

I reiterate my concern that for issues affecting everyone involved with utility dockets at the Commission, there is only ONE person representing the public, Suzanne Rohlfing, and only two others present at the first meeting who as attorneys represented a local government or citizen groups in a Commission docket, myself and Jerry Von Korff. At the second meeting, it was only Paula Maccabee and myself. The public and those representing public interests are not adequately represented in this group. As Alan Mitchell advocated in his comments for "Participating Utilities," echoed by Suzanne Rohlfing, "various interest groups" should be represented, including "local government, utilities, tribal government, state agencies, wind developers, generation owners, environmental groups, and the general public." There are no representatives of local governments on the committee. There are no representatives of tribal government on the committee. Many affected and involved state agencies are not represented (DNR, Dept. of Health), there are no environmental groups represented, and there is only one representative of the general public, one who is representing a landowner group. Very few requests were received to participate in this rulemaking, people who requested a seat at the table are not represented, and people who did not request a seat at the table are mysteriously included. There are 20 seats at the table, 21 with Ms. Agrimonti's dual representation of Xcel and ITC, and only ONE public person representing a landowner group, and three (two present) representing general public interest based on intervention in Commission dockets. This was a ratio of 20:1 and 20:2 at the first meeting. Many people did not attend the second meeting. This is not adequate representation of the public. While the "Wind Coalition" is represented, there is no one representing groups intervening in wind CoN and siting dockets – this exclusion is unwarranted. I again request that Goodhue Wind Truth be formally seated at the table, and I request that solicitations be send to those intervening and participating in other wind, transmission, pipeline and power plant dockets.

It's also problematic that the rule drafts are not posted in the 12-1246 docket. This is not acceptable. The public has been excluded from participating in the Committee and should have access at the stage where input could reasonably have an impact on rules ultimately forwarded by the Commission to rulemaking. Once the Commission acts on forwarding a draft to formal rulemaking, it's binary, too late for substantive changes. All rule drafts, minutes, synopses and drafts should be accessible to the public, their comments generally solicited and considered. This is also a way that the absent state agencies could comment on drafts for PUC, agency and public review.

7849 COMMENTS

Because we're working on 7849, the PUC Docket 10-874 rulemaking on the same chapter should be integrated into this docket because nothing seems to be happening in that docket.

Regarding the first synopsis, I offer a few observations after the first two meetings:

- "Members Present" should have a parallel "Members Absent" list. Members absent should provide for an alternate, as Ms. Rohlfing did at the second meeting, or lose their seat and allow for addition of someone else.
- In the "Issues Identified" as "issues for development in this rulemaking," I don't recall discussion of "simplify the property acquisition process" and note that land acquisition is beyond the scope of 7849 and 7850.
- **People do care about need** (this is important because elsewhere I've seen an ill-advised movement afoot to eliminate the public from need proceedings. Invariably when parties do wake up to a routing or siting near them, they want to address need and find it confusing that they are prohibited because need has already been determined.).
- P. 3, Subp. 4, Item A(1),"64 kV" should probably be "69 kV."
- P. 3, Subp. 4, Item B, because environmental and USFWS guidelines support review within 2 miles of a wind project footprint, that would probably be good measure for notice for affected landowners as well.

Regarding criteria for Certificate of Need:

Generally, while there is the addition of the reference in the introduction of Subp. 3 to 216B.243, Subd. 3, the statute related criteria shouldn't be deleted, and the specifics of the statutory criteria should be cut and pasted into the rules. For those not mandated in §216B.243, the authority should be clarified.

Also generally, the requirement of analysis of a "no build" alternative should be laid out more clearly in the criteria.

7840.0220 DEFINITIONS

Definitions to be added: "region;" "regional planning;" RTO v. ISO seems unclear; summer and winter peak demand; non-coincident and coincident peak should be defined and specified when "peak" is used.

Regarding maps:
Applications and notices should include:

- maps that show transmission system (location information only)(see DEED map)
- ; and
- a plat book from each effected county.

7849.0110 (add) This rule shall be stated in Notices including Notice for Public Hearing.

7849.0120 CERTIFICATE OF NEED REQUIREMENTS
This section represents a burden shift away from applicants, and instead should read:

> ~~B~~ C. whether the project proposed is ~~a~~ more reasonable and prudent alternative than any altenrative to the proposed facility, ~~has not been~~ demonstrated by a preponderance of the evidence on the record~~, considering:~~;
>
> ~~(1)~~ D. the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives;
>
> ~~(2)~~ E. the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives;
>
> ~~(3)~~ F. the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives; ~~and~~
>
> ~~(4)~~ G. the expected reliability of the proposed facility compared to the expected reliability of reasonable alternatives;

Minn. R. 7849.0220 (see CoN statute and 7849.0120, which should be carried over into 7849.0220, this is their burden of proof and production)

Subp. 1. Each application must contain **a** **narrow and specific definition of the need for the project and a** summary of the major factors that justify the need for the proposed project.

Subp. 2. **All Applicants – Regional Transmission Planning.** Each application for a proposed LHVTL **and LEGF** must contain a description of **regional transmission planning promotional practices and** whether the forecasted expansion of the integrated regional electric transmission system affects the applicant's claimed need for the proposed project. An application must also include data from the RTO on planned additions or retirements of regional transmission lines or generation facilities.

Minn. R. 7849.0250 PROPOSED LEGF AND ALTERNATIVES APPLICATION

An application for a proposed LEGF must include **a narrow and specific definition of the need for the facility and**:

A(6) a map of appropriate scale showing the applicant's system**, the regional system, and a plat map of each affected county**; if the applicant does not own or operate an electric system, the applicant shall provide a map of the area including the proposed facility **and region**;
D(3) its estimated average annual availability **and capacity factor**;

(7) **an estimate of its effect on rates systemwide and in Minnesota, assuming a test year beginning with the proposed in service date;** the estimate of the present value of the revenue requirement of the proposed facility **and an explantion of cost allocation**.

Minn. R. 7849.0260 PROPOSED LHVTL AND ALTERNATIVES APPLICATION

An application for a proposed LEGF must include a narrow and specific definition of the need for the facility and:

B. a discussion of available regional planning and reliability information including, including:

- (1) The most recent RTO regional planning study that includes the project;
- (2) **the most recent reliability report from North American Electric Reliability Corporation (NERC): and**
- (3) the reliability risks the proposed line is intended to address; and
- (4) the most recent electric stability study approved by the **regional planning organization.**

C (3) transmission lines with different design voltages or with different numbers, sizes, types of conductors, and **capacity expressed in MVA**;
(8) lower voltage options under 100 kV and use of distribution lines;
(~~8~~)(9) a no-build alternative~~, including lower voltage options under 100 kV and use of distribution lines.~~

D. (6) (DO NOT DELETE)

Minn. R. 7849.0270

The rule should require that co-incident and non-coincident peak both be provided.

Content of forecast (don't delete this section – utility applicants should have to demonstrate why these sections are not applicable. Perhaps specify that it's for utility applicants.)

ENVIRONMENTAL REVIEW

Minn. R. 7849.1000 – 7849.2100 (ENVIRONMENTAL REVIEW)
Authority specifically references only116D.04, but MEPA mandates Environmental Impact Statements and "environmental report" is not recognized or authorized by the statute.

Minn. R. 7849.1200 ENVIRONMENTAL ~~REPORT.~~ IMPACT STATEMENT.
Minn. R. 7849 must be corrected to state "**IMPACT STATEMENT"** in each place where it says "Environmental Report." There is no statutory authority for an "Environmental Report" document, and it was invented by the Environmental Quality Board in past rulemaking proceedings under its rulemaking authority. It's time to correct this to provide the review mandated by the Minnesota Environmental Policy Act, Minn. Stat. ch. 116D, and Minnesota Environmental Rights Act, Minn. Stat. ch. 116B.

The deletions in 7849.0230; 7849.1300-2100 should not occur, and should instead be left as written and amended to incorporate "Impact Statement" rather than "Report."

Alternatives Consideration: After our discussion of "alternatives" ranging from requirements that alternatives be adequately considered under MEPA and NEPA, and the horrific spectre of "endless alternatives," I want to note that it's crucial that "alternatives" be part of not only environmental review, but of the need review, specifically system alternatives that could address the need for a given project proposal. See attached *'Non-Transmission Alternatives': FERC's "Comparable Consideration' Needs Correction*, Scott Hempling, Electricity Policy.com (May 2013). When reading Mr. Hempling's article, substitute "FERC" for "Commission" and "RTO" for "utility" or "applicant" and the need, responsibility and obligation for proposal and thorough consideration of alternatives is mirrored in proceedings before the Commission. This is an important concept that should be reflected in the rules.

Much as FERC's role of alternatives consideration "needs correction," the state's responsibility of alternatives consideration is as much in need of correction as FERC. The burden of proof and production is on the utility applicants, yet where alternatives are concerned, they are given short shrift in environmental review, and in a Certificate of Need proceeding, the burden improperly shifts to intervenors to "whether a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record." Minn. R. 7849.0120(B). Information must be provided in the application regarding reasonable alternatives, and the criteria must address review of alternatives.

The language of this point can be simply corrected to address the Applicant's burdens, as below, followed by the language in Subpart C(1),(2),(3), and (4) (now D-G):

> **C. whether the proposed project has been demonstrated to be the most reasonable and prudent alternative.**
>
> > **(1)** the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives;
> >
> > **(2)** the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives;
> >
> > **(3)** the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives; ~~and~~
> >
> > **(4)** the expected reliability of the proposed facility compared to the expected reliability of reasonable alternatives;

At this time, we note the ever-important need for a public advocate or public intervenor and intervenor compensation for individuals and public interest and advocacy organizations. There is no entity in this or any proceeding before the Public Utilities Commission representing the public interest. Without a public advocate or public intervenor, the public interest is left without representation. Without funding, intervenors do not have resources to make their case.

These Comments are not all inclusive and I'll probably have more before the next meeting.

If you have any questions or require anything further, please let me know.

Very truly yours,

Carol A Overland

Carol A. Overland
Attorney at Law

Notice Form – Radio PSA

Utility Infrastructure Application Public Service Announcement

For immediate release
(date)

Contact: (Project Proposer)
(Agency Public Advisor)

ON (DATE), (PROJECT PROPOSER) FILED AN APPLICATION WITH THE PUBLIC UTILITIES COMMISSION FOR (DESCRIBE PROJECT WITH NAME OF PROJECT, AND SHORT DESCRIPTION OF INFRASTRUCTURE AND LOCATION).

LANDOWNERS AND RESIDENTS IN THE PROJECT AREA MAY BE AFFECTED BY THE PROJECT, AND LAND MAY BE TAKEN BY EMINENT DOMAIN FOR THIS PROJECT. THE APPLICATION IS AVAILABLE FROM PROJECT PROPOSER THROUGH A REQUEST AT ITS WEBSITE (ADDRESS HERE) OR BY CALLING (NUMBER HERE).

THE PUBLIC UTILITIES COMMISSION HAS A PUBLIC DECISION MAKING PROCESS AND OPPORTUNITY FOR PUBLIC COMMENT AND PARTICIPATION. PUBLIC MEETINGS WILL BE HELD IN THE PROJECT AREA AND NOTICE OF THESE MEETINGS WILL BE PROVIDED TO LOCAL GOVERNMENTS, LANDOWNERS, RESIDENTS AND MEMBERS OF THE PUBLIC. FOR FURTHER INFORMATION ON HOW TO PARTICIPATE, CONTACT (PUBLIC ADVISORX NAME) AT (EMAIL) AND (PHONE).

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‘Non-Transmission Alternatives’: FERC’s ‘Comparable Consideration’ Needs Correction

Non-transmission alternatives will not receive the consideration they deserve – and consumers will lose the reliability and cost-saving benefits NTAs may offer – unless FERC makes clear that transmission providers have an affirmative obligation to consider them.

by Scott Hempling

I. Overview and Summary

A. Transmission policy progress: 1996-2013

Since the early 1990s, FERC has issued a series of orders seeking to reconcile two conflicting facts:

1. Transmission facilities are controlled by individual utilities with retail monopolies over state-drawn service territories.
2. To accommodate consumers’ varied power supply preferences cost-effectively while maintaining and enhancing reliability, we must integrate the planning,

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pricing and operating of these transmission facilities over large regions that may span several utility service territories and state boundaries.

FERC's efforts have involved four major steps. *First*, Order 888, issued in 1996, aimed to stop undue discrimination by owners of transmission. It required each transmission owner to provide transmission service to all eligible customers on a non-discriminatory basis at just and reasonable rates. *Second*, some of those transmission providers, encouraged by Order 2000, formed regional transmission organizations. These RTOs would improve reliability and expand market boundaries by providing Order 888 transmission service on a regional, non-pancaked basis, while also creating markets for energy, capacity and ancillary services. *Third*, Order 890 required each transmission provider to create a "coordinated and regional planning process" consistent with nine principles: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation. These principles required transmission providers to consider all types of resources on a comparable basis. *Fourth,* Order 1000 builds on the three prior actions by requiring all transmission providers—those inside RTOs, those outside RTOs, and the RTOs themselves—to do something new: make, and knit together, regional transmission plans. These plans must account for each region's known, likely and possible power supply preferences and supply alternatives. To be valid, these plans must have emerged from processes that give "comparable consideration" to options other than transmission.[1]

A. Order 1000's goals remain unfulfilled

Implicit in Order 1000's requirements is this goal: Where a transmission provider seeks cost recovery for a transmission project, it must ensure that the project is the survivor of objective, head-to-head comparisons with feasible alternative solutions, including non-transmission alternatives (NTAs). This goal protects customers from transmission charges that are excessive relative to less costly and equally or more effective alternatives. Order 1000 thus changes the definition of obligatory transmission service. That service is not merely to transport electrons, not merely to link sources and sinks, but more broadly to plan and operate a region's transmission network most efficiently and cost-effectively to satisfy a region's varied needs.

When a transmission provider seeks cost recovery for a transmission project, it must show that the project was the best of feasible alternative solutions, including NTAs.

The Order 1000 compliance process has revealed a gap between FERC's aspirations

[1] Specifically, Order No. 1000 imposes on transmission providers "an affirmative obligation...to evaluate alternatives that may meet the needs of the region more efficiently or cost effectively [than local solutions]." (¶ 80). The regional processes must give "comparable consideration of transmission and non-transmission alternatives...." (¶ 155).

and industry practice. This gap has three features:

1. FERC and many transmission providers have stated that a transmission provider's obligation to give "comparable consideration" to transmission and non-transmission alternatives applies only to NTAs proposed by participants in the transmission planning process. That is, a transmission provider does not have an independent obligation to search for and assess alternatives, such as when no one proposes any.
2. There is disagreement over whether the procedures for considering NTAs, as submitted by the regions, will ensure "comparable consideration."
3. A distinct problem concerns cost recovery. If a transmission proposal serves regional needs, the provider can allocate and recover the costs regionally through a FERC-jurisdictional tariff. There is no comparable opportunity for regional cost allocation of an NTA because an NTA, by definition, is not "transmission" subject to FERC jurisdiction.

B. Purpose and summary

This paper assesses whether this state of affairs conflicts with the Federal Power Act and, if so, what corrections are necessary. Of Order 1000 requires transmission providers to assess only those NTAs that have proponents – thus authorizing transmission providers to disregard NTAs that lack proponents – it violates the Act's just and reasonable standard. Consideration of NTAs is a "practice … affecting" jurisdictional rates for transmission service and wholesale sales." For those rates to be just and reasonable, they must be based on costs that emerge from a prudent process. As found by courts and Commission precedent, prudent action is action engaged in by a reasonable person under the circumstances faced by that person.

A person with market power over an essential service, charged by statute with a duty to provide that service at just and reasonable rates, does not act reasonably by waiting passively for options to appear, rather than identifying and evaluating those options independently. Although some FERC precedent awards the utility a presumption of prudence (shifting to intervenors the burden of showing imprudence), that presumption makes no sense in these circumstances, because the combination of provider market power and bias (due to its opportunity to recover profitably through rate-base its transmission investment) means that the provider's self-interest conflicts with its statutory obligation.

That NTAs may not themselves be FERC-jurisdictional services (if they are not the transmission of electric energy or the wholesale sale of electric energy) does not excuse transmission providers from considering them. Ample precedent allows, and requires, FERC and providers of FERC-jurisdictional service to take into account non-jurisdictional facts.

In short, the Federal Power Act obligates FERC to impose on transmission providers an affirmative obligation to identify all feasible non-transmission solutions to transmission needs. This paper concludes with recommendations on how FERC can fashion this requirement. The recommendations focus on actions not only by FERC, but also by RTOs, non-RTO regional processes, other transmission providers and state regulatory commissions.

C. 'Non-transmission alternative' defined

There has been some confusion over this phrase, which Order 1000 does not define. It is necessary to distinguish among four concepts. The first three concepts fit within the statutory phrase "transmission of electric energy in interstate commerce,"[2] which triggers FERC jurisdiction. The fourth does not.

1. *Conventional transmission service:* This is the transportation of electrons over wires strung on towers and poles.
2. *Ancillary services:* These are the six services described in Order 888 as a sub-category of transmission service. They are needed to provide basic transmission service to a customer. These services range from actions taken to effect the transaction (such as scheduling and dispatching) to those that are necessary to maintain the integrity of the transmission system during a transaction (such as load following and reactive power support). Other ancillary services are needed to correct for the effects associated with undertaking a transaction (such as energy imbalance service).[3]
3. *Equipment that when operated "mimic[s] a wholesale transmission function."* An example is the storage devices described in *Western Grid Development, LLC*, 130 FERC ¶ 61,056 (2010). FERC deems such equipment to be providing a transmission service because it "mimics" a transmission function.
4. *NTA—an alternative to transmission service.* An alternative to transmission service is, by definition, not transmission service; it is a substitute for transmission service.

If demand response in a particular location defers or avoids the need to build transmission to carry power to that location, then it is an alternative to transmission—an NTA.

The four concepts are distinct but are easily confused when language is imprecise. For example, if something is an "alternative" to conventional transmission service but acts as an ancillary service, it is "transmission service" because Order 888 defined "ancillary services" to be part of transmission service. The same goes for something that, in its operation, "mimics" transmission service. And if it is "transmission service," it cannot logically be an NTA, because something that is "transmission" cannot be "non-transmission."

One source of confusion is the distinction between *technology* and *function*. What makes

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2 Federal Power Act § 201(b)(1).

3 Order 888 at text adjacent to n.348. The D.C. Circuit has paraphrased FERC's definition to mean, roughly, "services that ensure the availability of sufficient electricity at all times to meet fluctuating levels of demand." *Blumenthal v. FERC*, 552 F.3d 875, 878 (D.C. Cir. 2009). The six ancillary services are: (1) scheduling and dispatching services, (2) load following service, (3) energy imbalance service, (4) system protection service, (5) reactive power/voltage control service, and (6) loss compensation service.

something "transmission" for purposes of the Act is that it performs the *function* of "transmission of electric energy." FERC's six "ancillary services," for example, can all be performed by generation equipment (a technology). But because these services are "needed to provide basic transmission service to a customer" (a function), FERC deems them to be transmission.

Demand response is not, on the surface, a "transmission" technology, but can be used by RTOs to perform an ancillary service function.[4] On the other hand, not all demand response necessarily performs a transmission function. If by reducing demand, a demand response investment in a particular location defers or avoids the need to build transmission to carry power to that location, then it is an alternative to transmission—an NTA. Energy storage technologies, depending on their function, can act as transmission or non-transmission.

II. Transmission providers have a statutory obligation to identify and consider all feasible non-transmission alternatives to transmission projects—regardless of whether others propose such alternatives.

A. The Federal Power Act applies to transmission providers' 'practices' concerning non-transmission alternatives.

Section 206(a) provides that if a public utility's "practice ... affecting" a FERC-jurisdictional rate is "unjust, unreasonable, unduly discriminatory or preferential," FERC must determine the appropriate practice and "fix" it by order.[5] This provision gives FERC authority to order transmission providers to invite and consider NTAs on a basis comparable to proposed transmission projects.

1. What is a 'practice' and how does it 'affect' a jurisdictional rate?

In the context of Section 206(a), the term "practice" refers to "actions habitually being

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[4] See FERC Order No. 719, 125 FERC ¶ 61,071 (Oct. 17, 2008), adding §35.28(g)(1)(i)(A) of the Commission's rules. The rule requires that each "independent system operator or regional transmission organization that operates organized markets based on competitive bidding for energy imbalance, spinning reserves, supplemental reserves, reactive power and voltage control, or regulation and frequency response ancillary services (or its functional equivalent in the Commission-approved independent system operator's or regional transmission organization's tariff) must accept bids from demand response resources in these markets for that product on a basis comparable to any other resources…."

[5] Section 206(a) provides in part:

> Whenever the Commission, after a hearing had upon its own motion or upon complaint, shall find that any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.

taken by a utility in connection with a rate....“[6] A practice is a “consistent and predicable course of conduct of the supplier that affects [the utilities'] financial relationship with the consumer.”[7] FERC has “broad bounds of discretion [ ] to give concrete application to” the term “practices.”[8] This discretion “is limited to those methods or ways of doing things on the part of the utility that directly affect the rate or are closely related to the rate – not all those remote things beyond the rate structure that might in some sense indirectly or ultimately do so.”[9]

The Commission has relied on its authority over “practices ... affecting” jurisdictional rates to (a) modify deficiency charges for capacity;[10] (b) modify the allocation of a minimum capacity obligation among the load-serving entities within a regional transmission organization's footprint;[11] and (c) require regional transmission organizations to accommodate bids for demand response in organized ancillary service markets.[12]

2. How do a transmission provider's 'practices' concerning NTAs 'affect' jurisdictional rates?

A “practice” of considering NTAs “affects” FERC-jurisdictional rates in at least six ways:

a. A lower-cost NTA replacing a higher-cost transmission solution reduces the

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6 *California Independent System Operator v. FERC*, 372 F.3d 395, 400 (D.C. Cir. 2004).

7 *California Independent System Operator*, 372 F.3d at 403 (quoting *Mich. Wisc. Pipeline Co.*, 34 F.P.C. 621, 626 (Aug. 30, 1965)).

8 *City of Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985) (referring to Section 205(c)'s directive to utilities to file their “practices” with the commission).

9 *California Independent System Operator*, 372 F.3d at 403 (FERC's power to fix “practices” does not include the power to order changes to the utility's board). The Court there warned that although there is “an infinitude of practices affecting rates and service,” (citing *City of Cleveland* at 1376), there is not “also an infinitude of acceptable definitions for what constitutes a ‘practice....'” FERC does not have the authority “to regulate anything done by or connected with a regulated utility, as any act or aspect of such an entity's corporate existence could affect, in some sense, the rates.” *California Independent System Operator*, 372 F.3d at 401.

Note that the Court's statement (in the text above), that FERC's authority is limited to practices “that directly affect the rate or are closely related to the rate,” is narrower than what the statute says. The statute says only “affects,” not “directly affect or … closely related to….” Perhaps it was the Court's irritation with FERC's extraordinary reach into a corporate board that led it to use language narrower than the statutory text.

10 See *Municipalities of Groton, et al. v. FERC*, 587 F.2d 1296, 1302 (D.C. Cir. 1978) (upholding FERC's authority to examine and modify a “deficiency charge” imposed on members of the New England Power Pool, because the charge was “at least a rule or practice affecting the charge” for jurisdictional services; specifically wholesale power and reserve service).

11 *Connecticut Dep't of Public Util. Control v. FERC*, 569 F.3d 477 (D.C. Cir. 2009) (holding that FERC had authority to review ISO New England's annual calculation of the minimum amount of wholesale electric capacity that must be available to assure reliable service in the New England region; among other things, this “Installed Capacity Requirement” helped “find the right price,” making it a “practice . . . affecting rates”). See also *Cal. Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,076, at PP 540-56 (2007) (finding that maintaining adequate resources falls within Commission jurisdiction because it has a direct and significant effect on wholesale rates and services); *ISO New England, Inc.*, 119 FERC ¶ 61,161, at PP 18-30 (2007) (same).

12 FERC Order 719-A, 128 FERC ¶ 61,059 at PP 46-48 (2009).

delivered cost of wholesale power, thus reducing wholesale rates.

b. Competition from NTAs will induce providers of transmission service to lower their own costs. Transmission providers usually have market power, and therefore are insulated from market forces. But transmission market power can be tamed by subjecting it to competition from NTAs, just as generator market power can be tamed by subjecting it to competition from demand response—a point that FERC made in Orders 719 and 745.

c. Stimulating an NTA market will reduce the cost of NTAs themselves, an effect which then multiplies the prior two effects.

d. Continuous comparisons between NTAs with transmission will improve the transmission planning process. What begins as a project-by-project competition between NTAs and transmission can evolve into a process where NTAs, as potential lower cost alternatives, become the "base case" assumption against which transmission is measured. That planning process will discipline transmission costs.

e. NTAs improve system reliability by reducing the loads on transmission lines and the number of transmission lines that are vulnerable to outages caused by storm or sabotage. Since physical equipment needs to be backed up by redundant equipment, fewer vulnerable lines mean fewer redundant lines, thereby reducing transmission costs and rates.

f. NTAs affect not only transmission costs, but wholesale power prices as well. NTAs do more than merely provide a lower-cost substitute for particular transmission facilities. By reducing load on transmission lines, NTAs change power flows, potentially easing congestion in ways superior to the proposed transmission project. Reducing congestion reduces wholesale power prices. Absent NTAs (when they are less costly than transmission), generation will be more expensive than necessary because the LMP price at any location is based in part on the cost of transmission to that location. If an NTA is lower than the cost of transmission but is excluded from the market because the transmission provider fails to consider it, then the LMP will be higher than necessary.

These benefits demonstrate the linkage between NTAs and FERC-jurisdictional rates. This linkage, in turn, establishes FERC's authority to declare that transmission providers' failure to give careful, comparable, prudent consideration of NTAs is a "practice ... affecting rates" that FERC can investigate, find unjust and unreasonable, and modify by requiring different practices. Those different practices, as discussed in Part II, can include holding an open competition for alternatives to transmission, managed by an independent entity (in RTO regions, the RTO) with no stake in the outcome, at a stage sufficiently early in the planning process to give all alternatives—transmission and non-transmission—comparable opportunities to compete. (FERC is already encouraging competition among transmission providers by eliminating the incumbent's "right of first refusal" to build transmission for regional purposes. The right of first refusal had blocked non-incumbents from competing to supply transmission in specific situations.)

B. The Federal Power Act's 'just and reasonable' standard requires transmission providers to consider all feasible alternatives to transmission projects.

Order 1000 appears to mean that if no one proposes an NTA, a transmission provider has no obligation to consider NTAs. If that is FERC's policy, it subjects consumers to the risk of excess costs, in conflict with the Federal Power Act's consumer-protection purpose.[13] This purpose, embodied in the Act's "just and reasonable" language and FERC's prudence standard, requires public utilities to minimize all costs.

1. The prudence standard

In a competitive power market, if a seller bases its price on costs that fail to consider all feasible alternatives, it may lose customers to lower-cost competitors. It is the duty of regulators to mimic that competitive pressure by disallowing transmission costs that exceed feasible alternatives. This disallowance of imprudent transmission costs is regulation's substitute for competitive power market forces.[14] Companies whose survival depends on winning competitively must be alert to all options. Utilities that want cost recovery must do the same. This logic is echoed in decades of court decisions[15] as well as FERC precedent.[16] A utility must demonstrate that it

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13 *Public Systems v. FERC*, 606 F.2d 973, 979 n.27 (D.C. Cir. 1979) ("Both the Natural Gas Act and the Federal Power Act aim to protect consumers from exorbitant prices and unfair business practices. This purpose can be seen in the statutory requirement that rates be just, reasonable, and nondiscriminatory...."); *City of Detroit v. FPC*, 230 F.2d 810, 817 (D.C. Cir. 1955) (the Natural Gas Act's "primary aim" is "to guard the consumer against excessive rates"; numerous other court decisions hold that the NGA and the FPA are to be interpreted consistently).

14 See *Midwestern Gas Transmission Co.*, 36 F.P.C. 61 (1966) ("Managements of unregulated businesses ... have no alternative to efficiency," utility management "does not have quite the same incentive."), *aff'd sub nom.*, *Midwestern Gas Transmission Co. v. FPC*, 388 F.2d 444 (7th Cir. 1968); *Democratic Central Committee of the Dist. of Columbia v. Washington Metropolitan Area Transit Comm'n.*, 485 F.2d 786, 808, 810-11, 822 (1973) (price regulation substitutes for the "pressures of competitive markets, to prevent regulated companies from becoming 'high cost-plus compan[ies]' and to secure efficiency in the allocation of resources."); *Gulf States Utilities Co. v. Louisiana Public Service Commission*, 578 So. 2d 71, 94 (La. 1991) ("If a competitive enterprise tried to impose on its customers costs from imprudent actions, the customers could take their business to a more efficient provider. A utility's ratepayers have no such choice. A utility's motivation to act prudently arises from the prospect that imprudent costs may be disallowed.") (quoting *Long Island Lighting Co.*, 71 P.U.R. 4th 262 (N.Y. Pub. Serv. Comm'n, 1985)).

15 The just and reasonable standard imposes on utilities an affirmative obligation to find alternatives. They must "operate with all reasonable economies," *El Paso Natural Gas Co. v. FPC*, 281 F.2d 567, 573 (5th Cir. 1960); charge prices based on "lowest feasible cost," *Potomac Electric Power Co. v. Public Service Comm'n*, 661 A.2d 131, 138 (D.C. App. 1995); and use all available cost saving opportunities, *Midwestern Gas Transmission Co.*, supra, 36 F.P.C. at 70.

16 See *Minnesota Power & Light Co.*, 11 FERC ¶ 61,313 at p. 61,659 (1980) ("The combination of self-dealing, the selection of a questionable pollution control process, and the failure either (or both) to secure a performance guarantee and to seek damages constitutes overwhelming evidence of *imprudence* by MP&L and its Board of Directors.") (emphasis added); *Virginia Electric Power Co.*, 15 FERC ¶ 61,052 (1981) ("Disallowance of the repair costs would be a compelling conclusion had it been demonstrated that VEPCO executed a contract that left it

"went through a reasonable decision-making process to arrive at a course of action and, given the facts as they were or should have been known at the time, responded in a reasonable manner."[17]

In short, for cost-based rates to be just and reasonable, the costs reflected in those rates must be reasonable costs. For costs to be reasonable, the process by which they are incurred must be prudent. It is not prudent for a public utility not to consider all feasible alternatives. The costs that emerge from an imprudent process—one that ignores alternatives—cannot be reasonable costs.

For cost-based rates to be just and reasonable, the costs they reflect must be reasonable costs. For costs to be reasonable, the process by which they are incurred must be prudent.

Consider the analogy to negligence law. "The standard for determining whether utility management has acted imprudently is akin to the common-law standard for negligence: Did the utility act in a manner consistent with the performance of other similarly-situated contemporary utilities? If it did, its action cannot fairly be deemed the result of imprudent management."[18] A patient expects his dentist to know the state of the art. To maintain her expertise, the dentist doesn't depend on her patients, focus groups, or sellers of dental equipment. She studies medical journals, attends professional conferences, consults with high-performing peers, and takes regular re-certification tests. Anything less would be negligence. Applying this reasoning to NTAs: The Order 1000 obligation to "consult [ ] with stakeholders" on alternatives (Order 1000 at ¶ 68) cannot substitute for the transmission provider's obligation to use its own expertise to identify and compare alternatives. When proposing a regional transmission project for cost allocation after Order 1000, the transmission provider cannot discharge its evidentiary burden by saying merely, "We looked at the solutions others proposed." A reasonable person would not restrict her options to those suggested by self-interested entities looking to sell their own services, consumers hoping to minimize their short-term costs, and underfunded non-governmental organizations lacking technical expertise. The prudence standard requires the transmission provider to identify and examine every feasible alternative, regardless of whether someone else proposed it.

2. The relationship of prudence to cost-effectiveness

In the Order 1000 discussions, some have described the standard for transmission planning as one of "cost-effectiveness." Because both terms, cost-effectiveness and prudence, are in use (as noted above, key

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without remedy for the *negligent* acts of its contractor and left the ratepayers to pay the bill.") (emphasis added).

17 *Cambridge Electric Light Co.*, 86 P.U.R. 4th 574 (Mass. Dept. of Pub. Utils. 1983).

18 *Arizona Public Service Corp.*, 21 F.E.R.C. ¶ 63,007 at p. 65,103 (1982) (initial decision), aff'd in relevant part, 23 F.E.R.C. ¶ 61,419 (1983). See also Appeal of Conservation Law Foundation, 127 N.H. 606, 507 A.2d 652, 673 (N.H. 1986) (describing the prudence standard as "essentially apply[ing] an analog of the common law negligence standard for determining whether to exclude value from rate base").

FERC decisions talk of prudence), it is necessary to understand their relationship.

Cost-effectiveness is a characteristic of an *outcome*. An outcome is cost-effective if its benefit-cost ratio exceeds that ratio of all feasible alternatives. (An option that comes in second place, one that has a benefit-cost ratio that is positive but less positive than some other option, is not the cost-effective choice. It is wasteful, because it leaves something on the table; it sacrifices benefits that are attainable. It is economically inefficient. A fully competitive market would not tolerate that result. Nor can regulation.[19]

Prudence, in contrast, is a characteristic of a *decision-making process*. A decision-making process is prudent if it contains the procedures and professionalism that a reasonable person would use to make the decision at issue. Prudence is essential to cost-effectiveness. A decision that is imprudent cannot produce a cost-effective result, except by blind luck.

Prudence does not guarantee a cost-effective result. Decisions must deal with uncertainties. A utility might prudently gather the facts, identify uncertainties, analyze the probabilities of possible results, weigh the values necessary to choose among options given the uncertainties, but still make a choice that turns out to be higher cost than a non-chosen option. This result—a prudent decision producing an outcome that is not cost-effective—is unavoidable because no decision can guarantee a result.

Although prudence does not guarantee a cost-effective result, it is a prerequisite for cost-effectiveness. Otherwise, one is basing decisions on luck rather than facts and analysis (which itself would be imprudent). Since cost-effectiveness means the best benefit-cost ratio relative to all plausible alternatives, a process of identifying and assessing all feasible alternatives is an essential step. That is the step required by the prudence standard.

3. The relationship of prudence to process

Regulators lack the expertise of the utility's executives and experts. Regulators do not and cannot know of every alternative and its costs. What regulators can assess is the process by which a company arrived at its choice. They can ask these questions:

a. Was the process objective? Did the utility account for its biases (e.g., the opportunity to make a profit from its own investment vs. the foregone profit if a better solution is owned by someone else)?

b. Was the process defective because the people on the critical decision path had bureaucratic or career inducements leading them unreasonably to adopt one type of solution and ignore or reject others?

c. Was the process competent? Did the key advisors have the education and

[19] It is important to be clear on the term "cost-effective." I am equating cost-effective with "economically efficient" in a technical sense, i.e., no lower cost means exists to produce the same benefit. Some people use the term "cost-effective" to describe a range of alternatives, within which range the members all have positive benefit-cost ratios but vary in their "positivity," as in "more" or "less" cost-effective. I find that usage imprecise, because it implies that regulation of an entity with market power accepts a result other than minimum cost.

experience to evaluate properly all alternatives?

d. Was the process open? Did the utility inform all possible providers of all the options, give them the information necessary and sufficient time to respond?

When the transmission provider seeks cost recovery in a FERC rate case, it must demonstrate that its process was prudent. Given the necessity of this demonstration, it is more logical and less time-consuming for FERC to require the process upfront. In fact, requiring the process upfront is the only way to ensure that the transmission provider actually has alternatives to consider. Given this reasoning, FERC has authority to require that the transmission provider create a formal, objective opportunity for NTAs to compete, and to require that the provider search for alternatives independently of whether others present them. For that opportunity to provide the necessary cost discipline, it must be comparable to that enjoyed by transmission options, in terms of access to key information and relative certainty of financing and cost recovery. Absent such comparability, NTAs will not emerge on their own. If they do not, there is no assurance that the cost basis for transmission rates is just and reasonable.

Process was on FERC's mind in an analogous context: the awarding of transmission "incentives." In its 2012 Policy Statement, FERC declared that it—

> expects applicants for an incentive ROE based on a project's risks and challenges to demonstrate that alternatives to the project have been, or will be, considered in either a relevant transmission planning process or another appropriate forum. Such a showing should help identify the demonstrable consumer benefits of the proposed project and its role in promoting a more efficient, reliable and cost-effective transmission system.[20]

In other words, consumer benefits arising from a transmission incentive will not be "demonstrable" unless the transmission project survives a process in which alternatives have been considered. FERC then gives two examples of processes:

> "1. The applicant could show that its project was, or will be, considered in an Order No. 890 or Order No. 1000-compliant transmission planning process that provides the opportunity for projects to be compared against transmission or non-transmission alternatives."

> "2. The applicant could show that its project was considered by a local regulatory body, such as a state utility commission, that evaluated alternatives to its proposed project (transmission or non-transmission alternatives) and determined that the proposed transmission project is preferable to the alternatives evaluated."[21]

One hopes that the first example, referencing an Order 1000-compliant process, is a process improved by the recommendations in Part III of this paper; i.e., a process in which real alternatives are considered because the transmission project proponent actively

[20] *Promoting Transmission Investment Through Pricing Reform*, 141 FERC ¶ 61,129 at P 25 (Nov. 15, 2012).

[21] *Id.* ¶ 26.

identified and considered them, rather than waited passively for some to appear and, if none did appear, claim that such "opportunity" was sufficient to demonstrate the transmission project's "consumer benefits." (As discussed in Part II, an independent entity is, for this purpose, an appropriate substitute to the transmission project proponent for purposes of identifying and considering alternatives.)

There are two scenarios that do not fit with the foregoing. First, where the transmission project proponent is a merchant, it has no obligation to consider alternatives because it is taking a market risk. Because the merchant's customers will be volunteers rather than captives, they will have no cause to complain to FERC about an unreasonable rate Second, if the transmission project proponent is an independent transmission company (i.e., it is not affiliated with a load-serving entity), *and* is proposing a project for regional cost allocation, then the RTO (in RTO regions) or the regional process (in non-RTO regions) must actively invite, search for and consider the NTAs. If the independent proponent is not proposing regional cost allocation, then the project's customer would likely be a load-serving entity subject to state jurisdiction over retail rates, in which case the state commission would (based on its state law authority) require the LSE to consider alternatives.

4. Utilities may not delegate away their duties

For a transmission provider to ignore alternatives to its preferred option, unless someone else proposes one, is equivalent to delegating its public service duty to unidentified entities that might never show up. But a utility cannot delegate away its statutory obligations.[22] Even if delegation were legally permissible, it must be delegation to entities that are competent to do the job. Nothing in Order 1000 guarantees that competence. The likely proponents of NTAs will be (a) sellers of NTAs and their trade associations with a bias favoring their products, and (b) public interest groups or state commissions that may lack the expertise to offer cost-effective alternatives in a form sufficiently polished to compete with transmission proposals long-planned by the incumbent transmission provider. Order 1000 does not promise a prudent process.

[22] A utility that contracts away either its managerial powers or its essential assets cannot comply with its obligation to serve. Courts and commissions forbid such transactions. See, e.g., *Pennsylvania Water & Power Co. et al. v. Consolidated Gas, Electric Light & Power Co. of Baltimore*, 184 F.2d 552 (4th Cir. 1950) (striking a wholesale contract that gave one utility the power to control (a) the prices at which another utility could sell its output, and (b) the extent to which it could extend its plant, among other actions); the contract "disable[d] the utility from performing its proper function as a public utility under the public utility laws of Pennsylvania").

5. Presumption of prudence is inapplicable.

To relieve the transmission provider of an obligation to study alternatives is to grant the provider a presumption of prudence. There is FERC precedent for such a presumption, the effect of which is to shift to intervenors the "burden of going forward" on evidence of imprudence.[23] Under this approach, the absence of evidence of imprudence means that the utility, aided by the presumption, has satisfied its statutory burden of proof.

If undue preference involving transmission is traceable to the jurisdictional rate, the Commission would have power to effect a remedy under sec. 206.

This treatment should not apply here because there is no factual or logical basis for presuming a transmission provider's prudence. Except in the possible case of a transmission merchant, a transmission provider enjoys market power. It thus has an inherent bias favoring transmission (in the RTO's case, due to its expertise, institutional focus and membership; in the investor-owned utility's case, due to the profit potential from placing the project in rate base). Further, the transmission provider lacks experience in NTAs, and historically has made insufficient effort to invite NTAs. Where these factors exist, there is no basis for assuming that the utility's self-interest is aligned with the public interest. Where the transmission provider's interest conflicts with the need to examine alternatives, a presumption of prudence is illogical. FERC must require the utility to show prudence, specifically, by following a process that invites and studies all feasible alternatives.

C. The non-jurisdictionality of NTAs does not relieve transmission providers of an obligation to consider them.

That NTAs are not FERC-jurisdictional services does not relieve transmission providers of an obligation to investigate them. Under the Federal Power Act, a proposed rate fails the just and reasonable test if it imposes on customers a cost that exceeds feasible alternatives. That those alternatives are themselves outside FERC's jurisdiction does not make the proposed rate reasonable. This principle draws support from prior cases involving generation, as well as FERC's more recent demand response orders.

1. Generation precedents

In *Federal Power Commission v. Conway Corp.*, 426 U.S. 271 (1976), wholesale customers of Gulf States Utilities Company protested the utility's wholesale rate. They alleged price squeeze,

23 FERC presumes prudence until strong evidence arrives to rebut the presumption. This evidence includes a finding of imprudence by another federal or state agency. *Minnesota Power and Light*, 11 F.E.R.C. ¶ 61,312 at pp. 61,644 45 (1980). Thus an imprudence finding by the California commission had shifted the burden to the company for purposes of the FERC proceeding. Before FERC, the utility had offered only "vague generalizations about the problems inherent in all building projects. No specific evidence regarding the Vidal project was ever introduced." *Southern California Edison Co.*, 8 FERC ¶ 61,198 at 61,680 (1980), *aff'd sub. nom.*, *Anaheim, Riverside et al. v. F.E.R.C.*, 669 F.2d 799 (D.C. Cir. 1981).

based on a comparison of the utility's proposed wholesale rate with its retail rates.[24] FERC refused to order a hearing on the allegations, stating that retail rates were outside its jurisdiction. The Supreme Court reversed. The Commission had the jurisdiction and the duty to consider whether the proposed wholesale rates had an anti-competitive effect; and if so, to correct the problem. Section 205 of the Federal Power Act prohibits any "unreasonable difference in rates" or service "with respect to any . . . sale subject to the jurisdiction of the Commission." Referring to this provision, the Supreme Court declared:

> [A] jurisdictional [*i.e.*, wholesale] sale is necessarily implicated in any charge that the difference between wholesale and retail rates is unreasonable or anti-competitive. If the undue preference or discrimination is in any way traceable to the level of the jurisdictional rate, it is plain enough that the section would to that extent apply; and to that extent the Commission would have power to effect a remedy under sec. 206 by an appropriate order directed to the jurisdictional rate.

Because Gulf States and its municipal utility wholesale customers were competing for retail customers, Gulf States' retail rates "are part of the factual context in which the proposed wholesale rate will function. . . ."

The Court's decision in *Connecticut Dep't of Public Util. Control v. FERC*, 569 F.3d 477 (D.C. Cir. 2009), provides further support. The Court there affirmed FERC's jurisdiction to approve an ISO New England tariff provision allocating capacity reserve responsibilities among load-serving entities. Although Section 201(b) of the Federal Power Act denies FERC jurisdiction over generating facilities (effectively reserving that jurisdiction to the states), FERC there was not exercising jurisdiction over generation. FERC was regulating a "practice," engaged in by a FERC-jurisdictional entity (ISO New England), that "affected" wholesale rates; and wholesale rates are undeniably within FERC's jurisdiction. The same argument applies here.[25]

There also is an analogy to the Commission's landmark *Edgar* decision, establishing standards for sales by a wholesale seller to its affiliated monopoly retail utility (Boston Edison).[26] In these situations, the Commission requires evidence that the utility purchaser held a solicitation, and that—

24 "Price squeeze" is an anti-competitive pricing action by a wholesale seller. It occurs under a unique set of market conditions: The wholesale seller is also a retail seller, competing with its wholesale customer for consumers; and the wholesale customer depends on the wholesale seller for supply. Under these conditions, the wholesale seller has the incentive and opportunity to charge its dependent wholesale customer a discriminatory price designed to damage the wholesale customer's ability to compete at retail.

25 See also *Mississippi Industries v. FERC*, 808 F.2d 1525 (D.C. Cir. 1987), vacated in part on other grounds, 822 F.2d 1103 (D.C. Cir. 1987) (holding that the Commission had jurisdiction to allocate responsibility to take and pay for nuclear capacity because the allocation it "directly affects costs and, consequently, wholesale rates").

26 *Boston Edison Co. Re: Edgar Electric Energy Co.*, 55 FERC ¶ 61,382 (1991).

(1) the solicitation or negotiation was designed and implemented without undue preference for the affiliate, (2) the analysis of the bids or responses did not favor the [wholesale] affiliate, particularly with respect to evaluation of non-price factors, and (3) the [wholesale] affiliate was selected based on some reasonable combination of price and non-price factors. If the affiliate is not the lowest priced option, the applicant must provide sufficient justification for why the affiliate was chosen over alternative nonaffiliated sellers.[27]

Competition from NTAs can lower transmission prices and wholesale prices, reduce transmission provider market power and wholesale seller market power, and increase reliability.

A transmission provider that self-selects its own transmission project, then recovers (either directly, or in an RTO region indirectly through the RTO) the costs from its captive transmission customers, is similar to a monopoly utility that buys power from its affiliate. The similarity concerns the conflict between the utility's self-interest and its customer service obligation, in terms of its ability to use its market power to exploit consumers. Just as the Commission in *Edgar* required the wholesale seller to show it is subject to market forces, so must the Commission require the transmission provider to show that it is subject to market forces, by ensuring that NTAs have been considered.

2. Demand response precedent

Allowing transmission providers to disregard NTAs on the grounds that NTAs are not jurisdictional services conflicts with FERC's demand response policies, as set forth in Orders 719 and 745. In wholesale energy markets, demand response is an alternative to electric energy. FERC has required RTOs to accommodate demand side bids (from states that allow those bids) and to compensate winning bidders comparably to generation. The express reason for this requirement is "to ensure that rates are just and reasonable in the organized wholesale energy markets," and because demand response "directly affects wholesale rates."[28]

Opponents of Order 719 argued that FERC could not direct RTOs to accept demand response bids because demand response is not a FERC-jurisdictional transaction; it is neither the transmission nor wholesale sale of electric energy. FERC rejected this argument. It had jurisdiction to issue its order because demand response affects wholesale rates:

> Demand response has both a direct and an indirect effect on wholesale

[27] *Edgar*, at text accompanying n.63. Two other alternatives FERC offered were for the buying utility to (a) demonstrate the prices that nonaffiliated buyers in its market were willing to pay for similar services, or (b) offer benchmark evidence showing the prices, terms and conditions of contemporaneous sales of comparable products by nonaffiliated sellers. *Id.* at text accompanying notes 64-65.

[28] Order 745 at ¶¶ 2, 112; Order 719-A ¶ 47.

> prices. The direct effect occurs when demand response is bid directly into the wholesale market: lower demand means a lower wholesale price. Demand response at the retail level affects the wholesale market indirectly because it reduces a load-serving entity's need to purchase power from the wholesale market. Demand response tends to flatten an area's load profile, which in turn may reduce the need to construct and use more costly resources during periods of high demand; the overall effect is to lower the average cost of producing energy. Demand response can help reduce generator market power: the more demand response is able to reduce peak prices, the more downward pressure it places on generator bidding strategies by increasing the risk to a supplier that it will not be dispatched if it bids a price that is too high. Moreover, demand response enhances system reliability.[29]

These effects were sufficient to give FERC jurisdiction, even though demand response itself is not a FERC-jurisdictional activity:

> Petitioners miss the point. An RTO's or ISO's market rules [relating to sales of wholesale energy] are subject to our exclusive jurisdiction. These rules cover market bids from generators and from providers of demand response, which directly affect wholesale prices as discussed above. Accordingly, the Commission has found that it has jurisdiction to regulate the market rules under which an RTO or ISO accepts a demand response bid into a wholesale market.[30]

Each of these points has an analog in NTAs. Competition from NTAs can lower transmission prices and wholesale prices, reduce transmission provider market power and wholesale seller market power, and increase reliability. FERC also points out (Order 719-A at n.74) that "increasing the presence of demand response . . . provides market participants with better information about where they should and should not construct upgrades." More pressure from NTAs will enable market participants to make better judgments about where to locate generation and transmission. Not only can NTAs compete with proposed new transmission projects; NTAs can free up space on existing transmission systems, enabling more efficient location of generation and loads.

* * *

The foregoing precedents from generation and demand response do not mean that FERC has jurisdiction over providers of NTAs themselves. Under Section 201(b)(1), FERC has jurisdiction only over "public utilities" engaged in the transmission of electric energy or the wholesale sale of electric energy. Since an NTA is, by definition, not transmission, a provider of an NTA is not a provider of transmission service; therefore the provider of the NTA is not subject to FERC's transmission jurisdiction. (Where the NTA is generation sold at wholesale, however, FERC

29 Order 719-A at ¶ 47 (footnotes omitted).

30 Order 719-A at ¶ 52. FERC's decisions on demand response, including these jurisdictional arguments, are pending review in the D.C. Circuit.

would have jurisdiction over the seller and the sale.)

Nor do these precedents mean that FERC has the power to order a transmission provider to buy an NTA from its provider. FERC may have that power but the matter remains unclear. Consider again demand response. Demand response is neither the transmission of electric energy nor the wholesale sale of electric energy. Yet in Orders 719 and 745, FERC ordered RTOs (albeit in their capacity as market administrators rather than transmission providers) to (a) accommodate bids from demand response providers, and (b) pay the winning DR bidders the same locational marginal price that winning generators receive. As a result, LSEs that purchase through the RTO market must bear the cost of demand response that survives the competition. (Given Order 745's cost-effectiveness test, this obligation saves the LSEs money as compared to having no demand response bids). One might argue that if FERC has authority to require LSEs to bear the cost of demand response (an authority under review in a pending D.C. Circuit case), FERC has authority to order LSEs, at least in RTO markets, to buy NTAs where cost-effective. There are ways to argue for and against this proposition, so I place it here solely for purposes of discussion.

In sum, the question is not "Does FERC have jurisdiction over NTAs?" The question is "Can a rate for transmission service be just and reasonable if lower-cost alternatives to that service face obstacles to entry?" As explained throughout this Part I, the answer to that question is "no."

III. Recommendations for FERC, transmission providers, RTOs and states

The legal reasoning in Part II leads to this conclusion: FERC must ensure that any proposal for transmission cost recovery is accompanied by evidence that the transmission solution emerged from a planning process that included both (a) an *opportunity* for NTAs to participate, and (b) an *obligation* in the transmission provider to examine all feasible NTAs.

I emphasize both points because Order 1000 disregards the difference between opportunity and obligation. The rule requires the regions to create an opportunity for NTAs to be considered, but imposes no obligation that anyone consider NTAs that are not presented. If no one presents an NTA, no NTA gets considered—even if an NTA exists. FERC thus invites and approves a process that lacks a prerequisite for cost-effectiveness: an obligation to examine all feasible NTAs.[31]

As Part II.B explained, a rate cannot be just and reasonable if it not based on costs incurred through a prudent decision-making process. A decision-making process is

[31] Part of the problem may be imprecision in terminology. Some people use the term "NTA" to mean an entity proposing an NTA; other people view the term "NTA" to mean only the alternative itself. The latter is the clearer way to use the term. The point is that an NTA can exist, and have costs lower than proposed transmission projects, even though no particular entity is proposing the NTA. The difference is crucial to understanding the Federal Power Act. The purpose of the Act is not to give entities opportunities to participate in processes; the purpose of the Act, in the transmission context, is to protect consumers from excessive transmission costs.

prudent only if the decision-maker (here, the transmission provider ultimately seeking cost recovery) considers all feasible alternatives. Under FERC's opportunity-but-no-obligation approach, NTAs will be considered only if there is some entity having all of the following characteristics: (a) a self-interest in supplying an NTA, (b) an ability to invest in the NTA, (c) a reasonable opportunity to get cost recovery of the NTA, and (d) the resources to participate in the complicated, labor-intensive, expensive processes that involve transmission decision-making, where the dominant voices are usually those who have a for-profit stake in transmission winning over NTAs. The problem is that there is no basis for FERC to assume that in these regional processes any such entity will be present. Given the likely absence of such entities, FERC's implicit conclusion that these processes will necessarily produce cost-effective transmission proposals is not supported by substantial evidence. FERC can fix its legal error by accompanying (a) the opportunity for proponents of NTAs to have their projects considered, with (b) an obligation in transmission providers to examine feasible NTAs regardless of whether there are proponents.[32] In short, there must be some entity that is responsible for identifying all feasible NTAs and comparing them to the proposed transmission project. Who should have that obligation, and how it gets carried out, will depend on the context:

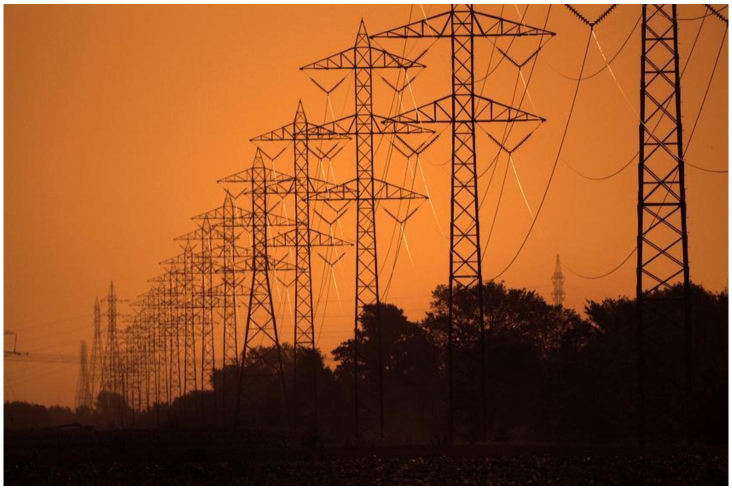
> **Within RTOs:** When the transmission provider seeking cost recovery is within an RTO, the RTO must be responsible for identifying and assessing NTAs. The RTO must either develop an internal staff expert on carrying out the NTAs, or contract with an entity that is expert in NTAs.
>
> **Outside of RTOs:** When the transmission provider seeking cost recovery is outside an RTO, the transmission providers that comprise the Order 1000 "region" must contract with an independent entity that is expert in NTAs.

For these purposes, "independent entity" does not include a transmission provider, whether a vertically integrated utility, an RTO or a transmission-only company. Just as FERC says there cannot be just and reasonable rates in a wholesale organized market without unobstructed demand response bids, so FERC must say there cannot be just and reasonable transmission rates unless cost-effective NTAs are identified by a disinterested body and that any such NTAs have an unobstructed opportunity to compete against the transmission project. The

32 Caution: The range of NTAs for which there is an obligation to consider is limited to feasible alternatives. An alternative is feasible if the transmission provider has a legal ability to contract with the NTA. For example, if the transmission provider is a load-serving entity and could have built a waste-to-energy plant in a key location that obviated the transmission project, and could have received cost recovery for the plant in its retail rates, at a cost lower than the transmission project, then the NTA is feasible. But a theoretical possibility that the state Department of Commerce might attract new renewable energy sources to an industrial park is not a feasible NTA.

opportunity is unobstructed only if it is run without bias.[33]

These two categories encompass all possible arrangements, with one exception. Specifically:



1. In states where LSEs are shopping for wholesale generation and need transmission service (because they have divested generation or have insufficient owned generation), they will be accessing transmission in either or both RTO and non-RTO regions. Either way, the requirements above will protect them.

2. In states with retail competition, the local LSE customarily still has a state law obligation to provide "provider of last resort" service. Again, that LSE will have protection from excessive transmission cost, whether it is buying transmission service from transmission providers within or outside an RTO.

3. The exception is the "merchant" transmission project. The merchant transmission project builds on spec and recovers (or does not recover) its costs entrepreneurially, with no assistance from government regulation. Since it has no regulated promise of cost recovery, it need not prove that its costs are lower than NTA costs. Of course, an LSE that purchases transmission from the merchant project will have to prove to its state commission that *it* has considered all alternatives. That obligation will discipline the merchant project's price.

FERC then must enforce the transmission provider obligation by rejecting any proposal for cost recovery of a transmission project unless it was subject to some objective, regulator-reviewed process that identified and considered all plausible alternatives, and emerged from that process with the best benefit-cost ratio.

There remains a problem. Consideration of an NTA is not comparable to consideration of a transmission project if the latter has a chance at FERC-prescribed cost recovery but the former does not. Either FERC has to find that the NTA is a necessary input to jurisdictional service and is therefore recoverable through the FERC jurisdiction; or FERC has to find that an LSE subject to state regulation will be able to recover its cost. There remains an unavoidable problem. If a state-regulated LSE has to bear 100% of the NTA cost, and that amount is greater than the state's share of a regionalized cost of the transmission project, the LSE's state

33 A winning NTA provider might argue that it should receive compensation equal to the cost of the transmission project they would have been built but for the NTA, drawing an analogy to the demand response bidder's entitlement to compensation at LMP rather that the bidder's bid price. That question deserves more thought than this paper's scope allows.

commission would not likely approve full cost recovery of an asset. This situation remains unsolvable unless FERC can find the authority to allocate the cost of such an NTA across the region, as it does with demand response.

To make the foregoing recommendations successful, the following institutional improvements are necessary as well:

1. FERC should direct every Order 1000 regional process to entertain NTAs even when there is not a specific transmission project to compete against.
2. FERC should direct every RTO to create a staff that is expert in stimulating and analyzing proposals for NTAs. Otherwise, the "judges" of NTA vs. transmission competition in RTO regions will be only those with expertise in, and a stake in, transmission. Under such circumstances, a market for NTAs is not likely to develop on its own. (In the non-RTO regions, this problem is addressed through the above-described requirement of an independent entity expert in NTAs.)
3. FERC should direct both its advisory staff and litigation staff to build expertise in NTAs, much as FERC created an expert staff on reliability. Only with such a staff can FERC rigorously review the NTA assessment processes carried out by the regions.
4. State commissions should require their utilities to hold open competitions for NTAs and create a path for cost recovery for those NTAs. If they lack the state statutory authority to do so, they should seek it. Note that by directing transmission providers to consider all feasible NTAs affirmatively, FERC helps state commissions. Alternatives to transmission, especially those relating to demand response and energy efficiency, can serve as alternatives to generation and distribution as well. Requiring a transmission provider to justify its expenditures by comparing them to all feasible alternatives will cause utilities to develop expertise and conscientiousness that will affect all their expenditures. Discipline imposed by one jurisdiction will assist performance improvement in the other jurisdiction.
5. State commissions should build internal departments with expertise on NTAs.
6. State commissions should consider jointly searching for NTAs that can substitute cost-effectively for regional transmission projects. On finding an alternative, they can reach informal agreements on allocating the costs to retail rates. Then each state would have a proceeding to approve the recovery in retail rates. The resulting promise of recovery would cause the NTA to be a plausible alternative to a regional transmission project. The RTO then would be bound to reject the transmission project, and/or FERC would be bound to reject its cost recovery. States acting in concert to find low-cost regional non-transmission alternatives is the best way to reduce their exposure to high-cost regional alternatives.
7. Amend the Federal Power Act to allow recovery through a FERC-jurisdictional rate of non-transmission alternatives that FERC finds are lower-cost than transmission alternatives. ■