BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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IN THE MATTER OF THE INVESTIGATION)
OF ELECTRIC TRANSMISSION ISSUES AND)
THE OPENING OF AN INVESTIGATORY) DOCKET NO. 08I -227E
DOCKET.)

PUBLIC SERVICE COMPANY OF COLORADO'S COMMENTS ON THE ISSUES SET FORTH IN DECISION NO. C08-0607

Public Service Company of Colorado ("Public Service" or "Company") hereby files its comments in response to Decision No. C08-0607 of the Public Utilities Commission ("Commission"), which called for interested parties to: (1) Comment on the issues set forth in the Commission's Preliminary Statement of Goals; (2) Provide legal analysis as to what authority the Commission possesses regarding these issues; (3) Suggest priority of goals and other areas of inquiry the Commission should be pursuing; and (4) Describe the appropriate level of involvement of the Commission in generation resource and transmission facility planning activities, in-state and regionally, in light of budgetary and resource constraints.

INTRODUCTION

Public Service believes that the opening of this transmission investigatory docket could not have come at a better time. The flurry of energy legislation over the last few years intensifies the focus on the need for comprehensive, efficient, and timely transmission development to implement state energy policy. At the same time that transmission is needed to help meet Colorado's renewable energy standard and enable desired generation development in designated energy resource zones, Public Service has with some projects encountered significant delays in obtaining the necessary approvals prior to constructing transmission facilities.

Accordingly, Public Service believes the outcome of this docket should be to clarify the intent to efficiently and proactively develop necessary transmission within the state and region, and to launch new, more efficient procedures that will facilitate transmission development. The Company proposes herein that the Commission streamline both the planning and CPCN application 'phases of transmission development by providing Commission input during the planning stage.

The Company observed at the outset that the Commission does have substantial authority over transmission facility planning and development in Colorado, but such authority is not plenary. The Federal Energy Regulatory Commission (FERC) also has considerable authority over transmission, including exclusive jurisdiction over the rates, terms and conditions of unbundled retail transmission in interstate commerce by public utilities, interconnection queues, and other matters. As a result, there are certain issues that must be decided at the federal level, and the results may not always be consistent with approaches this Commission may prefer. On these federal matters, the Commission has a persuasive voice that can be provided in FERC proceedings and regional transmission group meetings.

Overall the Company believes that the Commission in Decision No. C08-0607 and the accompanying Preliminary Statement of Goals has identified the important issues that need to be addressed. In saying that, the Company believes that certain issues may require a different emphasis or focus that what the Commission may presently be contemplating. To that end, although the Commission seemed to use

Decision No. C08-0607 as a scoping docket, Public Service will use these comments as an opportunity to give its preliminary views on the identified issues.

Public Service has organized these comments to concentrate on those issues over which the Commission has direct authority. Other issues are described briefly, with further comment appearing in attached appendices.

A. Streamlining the Process

Public Service has stressed its commitment to invest in and expand its transmission system to support achievement of state energy policy objectives and ensure a healthy and robust energy future in Colorado. Expanding the transmission grid is essential for delivering on the promise of a future that is more heavily influenced by renewable resources. In addition, there will be a need for greater integration of our transmission assets with those of other transmission providers in order to assure that not only local needs, but also regional needs are being addressed appropriately.

However, in order to achieve the necessary grid expansion in Colorado, consistent with both the requirements and goals of SB07-100 and the forces in the industry and the market generally, Public Service believes that it will be desirable for the Commission to streamline its processes and take a more interactive role at the transmission planning stage to give guidance to Public Service and others.

Previously, transmission planning has largely been reactive to load growth or specific plans for generation additions. The subsequent CPCN proceeding following such planning would then be focused on the specific demonstrated need driving the requested transmission expansion. Now, in accordance with SB07-100, planning and siting for the contemplated transmission to transport energy from energy resource zones is fundamentally different than it has been in the past. SB07-100 planning is a more proactive process based on strategic public energy policy and the potential for generation development in an area rather than actual generation proposals. Thus the demonstration of need in any subsequent associated transmission CPCN process is going to be less concrete than it has been in the past, which could potentially have ramifications for subsequent CPCN proceedings should the process not be modified to take this difference into account.

For the expedited development goals of SB07-100 to be achieved, it would be helpful for the Commission to provide up-front guidance to Public Service and participants in the SB07-100 stakeholder process. This Commission guidance could be obtained in multiple ways: (1) Commission staff has the ability to attend (and has in the past attended) actual planning sessions; (2) Public Service could meet with the Commissioners themselves on a periodic (e.g., quarterly) basis to inform them of transmission planning developments and obtain their input; and (3) informal work sessions could be scheduled with Commission staff. So long as such guidance is obtained during the planning stage, well before a CPCN application is filed, Public Service believes this process is appropriate and proper under the Commission's organic statutes and administrative rules.

In addition to providing guidance on line routing issues, the Commission can provide up-front guidance with respect to certain recurring issues in transmission line CPCN cases, including (1) noise level limitations by area and time of day; (2) EMF emissions; (3) right of way measurements; (4) conductor size; (5) conductor configuration; and (6) modeling runs. While some of these issues always involve factual considerations on a case-by-case basis, Commission guidance will help Public Service avoid having to submit revised or additional evidence, or go to rehearing, that delays ultimate resolution of the proceeding.

The goal of obtaining such input is to be able to present CPCN applications for projects identified and chosen through the stakeholder process that are aligned with Commission objectives, which in turn is necessary in order to achieve timely implementation of SB07100 goals. In order to present a CPCN application, the Company needs to undertake significant engineering work. Better input from the Commission will better enable the Company to focus its initial development efforts on projects that are more likely to come to actual fruition.

Public Service believes that input on those issues as well by Commission Staff or others in the stakeholder process is important in helping the Company anticipate and address issues that are important to the Commission at the application preparation stage rather than during a CPCN proceeding when it is more difficult to address those issues in a timely and adequate manner. In short, this pre-filing Commission input should also help streamline the CPCN application process.

B. Regional Transmission Planning Efforts

Before commenting on the specific issues set forth by the Commission, it might be useful for the Commission to look at Public Service's and Xcel Energy's long history steeped in regional cooperation for transmission planning. We are an active member company of the Colorado Coordinated Planning Group (CCPG), WestConnect, and the Western Electricity Coordinating Council (WECC). Each entity plays an important role in the regional planning process. A description of each regional transmission entity, followed by a discussion of how they work together in regional planning and cooperation, is attached hereto as Appendix A.

I. COMMENTS RE: PRELIMINARY STATEMENT OF GOALS

A. Appropriate planning horizons (short term and long term) for incremental additions of generation resources and transmission facilities, and the coordination of generation planning with transmission planning to ensure that an optimized electric system results

Public Service performs a variety of fundamental planning studies on an annual basis consistent with applicable reliability standards and good utility practices, as well as special purpose studies, including for generation and load interconnection requests. Every four years, Public Service performs transmission studies to coincide with its resource planning cycle. The Energy Resource Plans are developed by the Xcel Energy Services Resource Planning group and describe the Company's resource requirements for a ten-year period.

Public Service plans the transmission system consistent with the practice of the industry, which currently utilizes a ten-year detailed planning horizon as prescribed by NERC standards. While some stakeholders have suggested a longer planning period, we believe that attempting to develop and implement a longer range planning horizon, with the associated detailed models and generation and load assumptions necessary to do so, is impractical. The primary problem in pushing out the planning horizon is that it interjects still more uncertainty and speculation in planning assumptions. Even a fifteen to twenty year planning horizon has this same problem and is ultimately not that useful or reliable.

Various national standards and drivers require utilization of a ten-year planning horizon that includes technical models that represent transmission facilities, loads and resources. NERC reliability standards mandate electric utilities to perform many different assessments to verify the adequacy of a transmission system using a short-term (1-5 year) and a long-term (6-10 year) planning horizon. These include planning studies done under standards TPL-001 through TPL-004, which are a series of required studies that must be performed under many conditions for a one to ten year planning horizon[1]. FERC Order 890 requires coordinated and open regional planning and also requires a 10-year planning model. Public Service's WestConnect studies are part of the FERC 890 process, and they are utilizing 2013 and 2018 model years.

Occasionally Public Service and other utilities will perform high level strategic or visioning-type planning studies on a slightly longer time horizon, such as the High Plains Express project. Less detailed visioning studies may extend to around twenty years out, but that is about the realistic maximum extent to achieve any kind of contextual value from the results. With each increment of time past the ten-year horizon, increasing uncertainty in key assumptions causes increasing inability to provide any realistic basis for developing a definitive and actionable transmission plan.

In lieu of adopting a longer term transmission planning horizon, the Company believes that it would be more efficient, effective, and beneficial to establish criteria under Senate Bill 07-100: (1) on how much incremental new or net/total transmission injection capacity should be planned between various Energy Resource Zones and load centers; and (2) on how far in advance of generation development should transmission be developed. SB07-100 provides the opportunity to establish these criteria, which is presumed to be in the public interest.

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[1] *See* NERC Standard TPL-001, TPL-002, TPL-003, and TPL-004.

Public Service coordinates its transmission planning with resource planning to the extent allowed by law and regulations of the FERC. Individual generator and load interconnection requests are handled on a sequential basis, and are completed according to FERC and Public Service rules.

B. Appropriate incentives, a reasonable system of cost recovery, and an equitable cost allocation mechanism to treat the incremental expansion of the transmission system

The Sixty Sixth General Assembly passed SB 07-100 upon recommendation by the 2006 Transmission Task Force on Reliable Electricity Infrastructure. In its November 1, 2006 Report, the Task Force recognized that "Colorado's ability to ensure continued affordable, reliable electricity and to build a vibrant economy depends on sufficient transmission capability," and "[t]oday the system is strained and, if current trends continue, there will not be adequate transmission to meet the needs." The Task Force also made four recommendations, including: establishing a transmission cost recovery rider to create a robust and reliable transmission system to meet Colorado's future energy needs; increased governmental involvement with organizations like the Colorado Coordinated Planning Group; and appropriate adequate funding for the Public Utilities Commission to actively participate in regional electricity transmission planning, reliability and regulatory forums.[2]

2 The Report on the Task Force on Reliable Electricity Infrastructure is available at: http://www.dora.state.co.us/puc/projects/ReliableInfrastructure/FinalTFReport11-01-2006.pdf.

SB 07-100, which has been codified in relevant part at § 40-5-101(4), C.R.S[3], was enacted to implement these recommendations. Consistent with this new statute, the Commission approved Public Service's Transmission Cost Adjustment (TCA)[4], an annual adjustment rider designed to recover the costs associated with transmission investment made since the Company's last Phase I electric rate case for which the Company has been granted a Certificate of Public Convenience and Necessity ("CPCN") or for which the Commission has determined that no CPCN is necessary. In effect, the TCA allows recovery of all of the costs associated with transmission investment made since the Company's most recent Phase I electric rate case.

Public Service believes that C.R.S. § 40-5-101(4) establishes the appropriate incentives and a reasonable system of cost recovery for transmission lines located within Colorado. If the Commission would like to look at further incentives to induce transmission construction in Colorado, a recent action taken by the Federal Regulatory Energy Commission (FERC), *In re Xcel Energy Services*[5], is instructive. Currently, at

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3 Section 40-5-101(4), C.R.S. provides as follows:

(a) A public utility shall be entitled to recover, through a separate rate adjustment clause, the costs that it prudently incurs in planning, developing, and completing the construction or expansion of transmission facilities for which the utility has been granted a certificate of public convenience and necessity or for which the commission has determined that no certificate of public convenience and necessity is required. The transmission rate adjustment clause shall be subject to annual changes, which shall be effective on January 1 of each year.

(b) To provide additional encouragement to utilities to pursue the construction and expansion of transmission facilities, the commission shall approve current recovery by the utility through the annual rate adjustment clause of the utility's weighted average cost of capital, including its most recently authorized rate of return on equity, on the total balance of construction work in progress related to such transmission facilities as of the end of the immediately preceding year. The rate adjustment clause shall be reduced to the extent that the prudently incurred costs being recovered through the adjustment clause have been included in the public utility's base rates as a result of the commission's final order in a rate case.

4 *See* Decision Nos. C07-1085 (December 24, 2007) and C08-0157 (February 13, 2008) in Docket No. 07A-339E.

5 *See In re Xcel Energy Services, Inc.*, 121 FERC ¶ 61,284, Docket No. ER07-1415-000 (December 21, 2007).

the federal interstate transmission line level Public Service's transmission formula that is found in the Xcel Energy OATT does not include CWIP in the calculation of the current transmission rate that is effective June 1 of each year. As projects are placed in service, they are included in the formula at that point. There is no FERC order for Public Service's transmission allowing CWIP in rate base.

However, FERC has shown a willingness to provide incentives for transmission line investments in its recent decision, *In re Xcel Energy Services,* which allowed CWIP in rate base for certain multi-state projects of NSP Companies (Northern States Power Company of Minnesota and Northern States Power Company of Wisconsin, both Xcel Energy subsidiaries). FERC granted Xcel Energy Services, Inc.'s request for incentive transmission rates as part of its plan for six transmission expansion projects to serve their five-state service territory that will cost approximately $1 billion to meet state renewable energy generation standards and serve increased power demand.

More specifically, Xcel Energy, on behalf of NSP Companies, filed proposed modifications to the NSP companies' transmission rate formula under the MISO open access transmission and energy markets tariff. The modifications permit two types of incentive rate treatments for the upgrades: recovery of return on 100 percent of prudently incurred construction work in progress (CWIP) and recovery of prudently incurred costs of transmission facilities that are canceled or abandoned for reasons beyond the NSP Companies' control. FERC held that authorizing the CWIP treatment and abandoned plant recovery for the projects would enhance cash flow, reduce interest expense, assist with financing and improve credit quality.[6] Public Service attaches as Appendix B the *In re Xcel Energy Services* FERC decision.

Xcel Energy anticipates making similar filings with FERC for transmission line investment incentives associated with multi-state transmission line projects, such as High Plains Express, which would tap renewable resources within and outside Colorado. Xcel Energy would appreciate the Commission's support in such endeavors.

C. Transmission pricing across multiple utilities ("postage stamp" rates vs. "pancake" rates); improvements to the transmission interconnection queue process; expansion of control areas; and full compliance with FERC Open Access, Order 890, and Order 2003 policies

As a general observation, the Company believes it is important for the Commission to understand applicable FERC rules because the Company is obligated to follow them as it plans and operates its system.

1. Transmission Pricing Across Multiple Utilities – Appendix C

Appendix C shows by way of illustration how costs are allocated in other Xcel Energy geographic areas. Xcel Energy has generally supported Postage Stamp cost allocation for 345 kV projects and higher. However, Public Service Company of Colorado does not have an organized market with participants for the purpose of cost allocation. Until that occurs, Public Service would need to look at a joint ownership model for regional projects, and determine any cost allocation by agreement of the parties.[7]

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6 *Id.* at pp. 21-23.

7 The Company would observe that, notwithstanding the emphasis on regional transmission in Decision No. C08-0607, and by FERC generally, certain parties for various reasons – e.g., because of certain cost-shifts – have been reluctant to participate fully.

2. Interconnection Queue (LGIP) reform – Appendix D

Interconnection queue clustering is a generation interconnection process requirement under the Federal Energy Regulatory Commission ("FERC") rules and regulations. Within the last five years FERC has issued three decisions on interconnection queue practices and reform. *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003); *Interconnection for Wind Energy*, Order No. 661, FERC Stats. & Regs. ¶ 31,186 (2005); and *Order on Technical Conference Re: Interconnection Queuing Practices,* 122 FERC ¶ 61,252, Docket No. AD08-2-000 (March 20, 2008). Xcel Energy has suggested numerous interconnection queue reforms in the latter docket in its filed comments, which are attached to this pleading as Appendix D.

To briefly summarize these comments, Xcel Energy believes that there are several problems with the LGIP process which compromise the timeliness and fairness of processing interconnection requests and the effective use of Xcel Energy's transmission resources. Public Service, like many other transmission entities around the country, suffers from an oversubscribed queue consisting of many projects that will never be placed in service. Entering the queue is a fairly simple process that only requires a completed Interconnection Request form and a $10,000 refundable deposit. For the Public Service system, of the 43 generation projects that have been submitted to the queue since 2003, only six have signed PPAs and have been, or are currently being built. In processing these 43 queue submissions, Public Service has completed 77 LGIP studies representing thousands of both in-house and consulting hours of work.

This backlog demonstrates that the Order No. 2003 interconnection queuing process was not designed to work with the large number of requests such as those that have been received over the past two years. Unfortunately, transmission planning resources are extremely limited, and the Order No. 2003 study deadlines are short. As a result, the Public Service transmission planning function has spent a significant amount of time over the last several years planning for the interconnection of generation projects that will never be constructed and placed in service. Unless this process is changed, serious impediments to both the timely infrastructure expansion needed to support increased renewable energy development and interconnection of other viable generation projects that hold unfavorable queue positions today could inhibit timely achievement of Colorado state renewable energy standards.

Xcel Energy thus believes additional reforms are needed to enhance the effectiveness of the LGIP to ensure more timely and equitable interconnections to the Public Service transmission system. Xcel Energy strongly recommended to FERC to allow transmission service providers like Public Service who are not in RTOs to propose and impose meaningful LGIP milestones that developers would be required to satisfy going into the Facilities Study phase. These milestones should be vigorous demonstrations of the viability or of the active development status of a generation project. Suggested milestones could include the demonstration of certain firm commitments such as signed PPAs, financing arrangements or commitments, land leases, air or land use permit applications, generation equipment purchase orders, Engineer, Procure, Construct Agreements or other demonstrations of mature development. Such a "first complete, first-served" process would allow Public Service to allocate limited transmission planning resources to the generation projects that will actually be constructed.

Public Service appreciates any Commission support of the queue reforms that have been proposed to FERC.

3. Expansion of Control Areas – Appendix E

The issue of whether Public Service's transmission control area should be expanded relates to the effect of intermittent resources, such as wind and solar generation, on electric system operations and reliability. Public Service does believe that a slower staged approach to adding additional variable output resources is prudent in the future. This will provide time to experience operation with existing levels of wind resources, and permit our assessment of ways to add traditional generation fleet dispatch flexibility or regional generation put options. The staged approach has caused some concern with renewable generator stakeholders, and one suggested method for addressing reliability concerns is to expand Public Service's control area. For example, if exceeding 20% wind penetration causes reliability concerns within Public Service's control area of approximately 7,000 Megawatts, an expanded control area with 10,000 Megawatts could allow integration of greater amounts of wind into Public Service's system without exceeding the 20% concern threshold.

Public Service explores expansion of control area ideas, and studies and initiatives underway to address these issues, in Appendix E.

4. Compliance with FERC Orders

Public Service and Xcel Energy believe they are in full compliance with FERC policies regarding Open Access, Order 890 and Order 2003. For further comment on FERC compliance, see Section I.G., below.

D. Regional cooperation in cost allocation, as well as siting and permitting

1. Cost Allocation

Public Service's comments on cost allocation among multiple utilities is described above in Section I.C.1., and in Appendix C.

2. Siting and Permitting

In Colorado, the typical siting and permitting process for new or upgraded transmission lines is time consuming, taking five years or more, as shown in the chart below:

	Activity	**Timeframe**
Step 1	**CPCN approval from CPUC**	**6 – 24 months**
Step 2	**Siting Process – land use & environmental analysis, public/agency involvement, alternate route ID, landowner discussions**	**12 – 18 months**
Step 3	**Applications & hearings w/ multiple local jurisdictions**	**6 – 12 months**
Step 4	**Appeal any denials to CPUC**	**6 – 18 months**
Step 5	**Total Siting & Permitting**	**30 – 72 months**
	Adjusted for overlap between Steps 1 & 2	**18 – 42 months**

Siting and permitting generation facilities is generally less controversial than transmission because impacts are contained within a specific site and perceived economic benefits are greater. Further, industry and regulatory changes have resulted in quicker, market-driven development of generation (both fossil and wind). As a result, a mismatch exists today between transmission and generation development processes and timeframes. Some of this mismatch is being addressed in the SB07-100 process by allowing for CPCN approval with a showing of "future" need and to meet the state's renewable energy standard. However, a mismatch still exists to the extent a transmission line takes around five years to build and a wind facility can be completed in two years.

State siting authorities can help address this mismatch by reviewing proposals for both transmission and generation facilities. Public Service favors an eventual move to a state, as opposed to local, permitting authority to ensure more predictability in the statewide planning and developing of transmission and generation facilities. State permitting frees local government decision-makers from having to make local decisions about projects with regional benefits and impacts, provides energy planners and developers with a measure of predictability and consistency about permitting timelines and costs, and provides for ample local input on decision-making and also for mitigating local impacts. The focus is on impartial decision-making about statewide benefits to the economy, environment and system reliability.

The current approval process involves getting approval from county and municipal jurisdictions through which a proposed transmission project will run. Local jurisdictions aren't always best equipped to evaluate statewide or regional reliability and economic benefits. Local permitting processes are all very different in terms of permit types, application requirements, review criteria, and decision-making. Some local jurisdictions have no land use regulations pertaining to energy facilities. Others are extremely ambiguous. Further, there often are "seams" issues with routing alternatives at jurisdictional boundaries. In short, multiple processes with multiple jurisdictions for one project is inefficient and costly for both the applicant and the local jurisdictions.

In 2004, the Colorado Legislature passed SB05-160 (codified at C.R.S. § 29-20-108), which set up an appeal process of local government land use decisions to the Colorado Public Utilities Commission. A description of the essential elements of this legislation is attached as Appendix F.

This legislation is helpful to resolve unreasonable land use decisions involving transmission lines and other utility facilities, but it does have shortcomings. Most notably, the Commission review of land use decisions involves litigation, which provides opportunities for uncertainty, delay, and appeal.

The first case brought to the Commission under § 29-20-108 involved Tri-State Generation and Transmission Company's proposed upgrade to a transmission line in San Miguel County (Docket No. 03A-192E, Decision No. C04-0093, January 26, 2004), Tri-State argued that an undergrounding condition imposed by the San Miguel Board of County Commissioners would be prohibitively expensive, and should not be imposed on its 44 cooperative electric association members. The Public Utilities Commission held that, to the extent that total costs for underground construction were greater than overhead construction, and interested stakeholders were not willing to pay the difference, the undergrounding condition was unreasonable and the county's resolution would be reversed. *Id.* at 13-14, 20-22. However, the litigation before the Commission was delayed due to cost assessment and other issues, and then the decision was appealed to the San Miguel County District Court. Public Service believes the construction of a needed transmission line upgrade was delayed for three or more years as a result of the litigation.

Through its participation in the Governor's Task Force on Electric Reliability in 2006, Public Service initially proposed that the Task Force consider recommending the establishment of a new state government entity charged with approving transmission siting and construction in Colorado. Ultimately the proposal was dropped to address more urgent issues, but it remains a goal of Public Service to streamline the siting and permitting process to avoid protracted litigation and the delay of needed transmission and generation facilities.

In most states, the state utilities commission acts as the state's primary siting authority, although some state PUCs have delegated authority to entities such as a state land use commission, energy commission or department of natural resources. Other states have established siting boards, corporation commissions or other similar entities that act somewhat independently from the state PUC, but which typically rely on PUC staff for support.

Under a state siting authority approach, an applicant would not be required to acquire separate land use permits from each individual local jurisdiction through which a project is proposed. Public Service believes, however, that any fair and efficient state permitting process must afford ample and meaningful opportunities for input from all affected stakeholders, including city and county governments, and affected landowners.

Public Service continues to assess whether local siting authority makes sense for Colorado given the delays that have occurred in the San Miguel County matter and other cases[8]. Moving to a state siting authority would need to involve legislation after careful consultation with cities, counties, and the Commission. Public Service would not advocate eliminating local government participation in siting decisions. We would continue to implement our overall routing and siting philosophy of inclusive and comprehensive public involvement and input into determining the best route/site for any given project. However, the Company remains concerned with the current process, which can delay needed transmission projects and hinder state and legislative transmission expansion goals.

E. Compliance with mandated Colorado Renewable Energy Standards, Demand Side Management goals, Resource Planning requirements and Climate Action initiatives, and coordination of these efforts with similar requirements in other western states

Public Service's recent Colorado Resource Plan filing illustrates how it is complying with the legislative, Commission, and gubernatorial goals associated with renewable energy, demand side management, resource planning, and the Governor's Climate Action Plan. Public Service's preferred resource plan proposes significant renewable energy and DSM additions, resource additions that go above and beyond the levels required to meet the minimum goals of HB07-1037 and HB07-1281. We presented a plan that makes significant carbon dioxide emission reductions from 2005 levels, both through increasing the percentage of non-carbon-dioxide emitting resources in our portfolio and by replacing existing coal facilities with combined cycle gas

[8] In another matter (prior to the passage of C.R.S. § 29-20-108), *City of Louisville* (Docket No. 00D-583E, Decision No. C01-268, March 21, 2001), Public Service Company of Colorado contended that an undergrounding condition imposed by the City was unreasonable because it would cost its general body of ratepayers an additional $8 million to accomplish. The Public Utilities Commission, after public and evidentiary hearings, held that the transmission line upgrade was a matter of statewide concern, and "allowing municipalities to impose piecemeal regulations over public utilities would seriously damage the reliability of utility services the citizens of this state currently take for granted." *Id.* at 16. While the result was satisfactory, the litigation delayed construction of the line.

generation. Public Service's preferred resource plan includes in the resource acquisition period from October 2007 through the end of 2015 a total of 537 MW of demand side management, which is above and beyond what is required by HB07-1037. When we compare generation in 2007 to 2015, we see that we will meet significantly more of our customers needs with renewable energy and significantly less with natural gas fired energy. We also will reduce the percentage of energy served by coal-fired resources.

In order to expand Public Service's renewable energy portfolio, substantial transmission will need to be built. The first wind acquisition will encourage development in Zones 1 and 3. Under the plan, about 300 MW of additional transmission capacity will be available by the first in-service date (2010) in northeastern Colorado (Zone 1) and 80 MW will be available in southeastern Colorado (Zone 3). Subsequent solicitations will benefit from the full build-out described in the Company's SB07-100 filing, more specifically the Eastern Plains Transmission Project (as originally proposed or as modified), the 57-mile transmission line from Lamar, CO into Baca county, and the Pawnee-Smoky Hill 345 kV Transmission line project that was submitted for a CPCN. The Wind and the All-Source RFPs are timed so that those projects could also take advantage of this full build out. The Concentrating solar thermal set-aside would likely be located in the San Luis Valley (Zone 4), which under the SB07-100 filing indicates an additional 200 MW of additional transmission capacity is available to interconnect a new resource.

In addition, Public Service has an existing interruptible load program in place that allows the Company to call interruptions of certain customers who voluntarily take this service under a tariff. The Company has recently proposed a new program under Advice Letter No. 1495-Electric. The program expansion is to allow greater participation by the lowering the interruption capacity threshold and more flexibility in how customers participate by leveraging the customers energy management systems (EMS) for managing the load reduction. Use of the interruptible program should also benefit the transmission system.

While Public Service is not subject to renewable energy mandates or similar initiatives in other states, as noted above it is participating in various regional groups and discussions about western states' goals. One issue that Public Service and the Commission must keep in mind is that, unlike Colorado's renewable energy standard, many western states' standards require that 100% of the renewable energy requirements must be located in-state. This will make it more challenging to export Colorado's renewable energy to other states.

F. Protection of the public's quality of life by minimizing the effects resulting from expansion of the transmission infrastructure

In passing legislation allowing for PUC determination of reasonable noise levels for electric transmission lines (§ 25-12-103(12), C.R.S.), the General Assembly stated that it was a matter of statewide interest and concern that the State of Colorado have an adequate, reliable, and cost-effective electricity infrastructure to serve the needs of the people of Colorado for their homes, businesses and industries. The general assembly found that electric transmission facilities are linear and may pass through several local jurisdictions and zoning districts. Therefore, the General Assembly left it up to the Commission to determine whether the predicted audible noise levels from proposed transmission facilities were reasonable.

Section 4 CCR 723-3102(c) ("Rule 3102(c)") of the Commission's Rules Governing Electric Utilities requires a utility applying for a CPCN for transmission facilities to describe its proposed actions and techniques for cost-effectively mitigating noise associated with the proposed facilities. The rule further requires the utility to provide computer generated audible noise studies of the proposed transmission line showing the potential noise levels expressed in dB(A) and measured at the edge of the transmission right of way. Some of the techniques recommended to achieve cost-effective audible noise mitigation are larger conductors, bundled conductors, corona-free hardware, conductor quality, handling and packaging, construction techniques, conductor tensions and design alternatives considering the spatial arrangement of phasing of conductors.

Public Service generally proposes a conductor size and type that balances a number of issues such as audible noise, electromagnetic fields and economics. The Company usually utilizes "non-specular" wire, which reduces reflection, and adds to the aesthetics at a small incremental cost, and a standard bundled conductor configuration with corona-free hardware (a bundled configuration refers to the use of two wires per phase, in a vertical configuration, which has the benefit of increased capacity while at the same time reducing the audible noise that would occur with only one wire per phase). Industry recognized prudent techniques also is employed, which significantly reduce the effects of corona and thus corona-generated audible noise. The phases are spaced adequately apart so as not to create an excessive voltage gradient, which, if not taken into account, would generate constant and excessive corona. The conductor is handled and packaged properly, and the construction crews use well-maintained equipment and proper construction techniques, so as not to damage the conductor. A damaged conductor can emit corona and thus emit higher sound levels than an undamaged conductor. Proper line tensions are also applied so as not to create a loose conductor; as with a damaged conductor, a loose conductor emits higher sound levels than a conductor of proper tension. By using these prudent techniques the transmission lines operate as quietly as possible given the voltage and location. All of these requirements are included in Public Service's Construction Specifications, which follow IEEE standard 534, IEEE Guide to the Installation of Overhead Transmission Line conductors.

With respect to EMF emissions, Public Service often proposes to use two basic avoidance techniques. First, Public Service has studied and uses the technique of reverse phasing (referenced in the Commission rule as "design alternatives considering the arrangement of phasing of conductors"). The reverse phasing application reduces the electromagnetic fields created by transmission lines. The second minimization avoidance technique Public Service can reasonably employ is the use of higher structures. The structures used can be higher than the minimums required for ground clearance by the National Electric Safety Code. A small height increase can provide an additional electromagnetic field reduction along with increased safety clearances.

With every transmission project, Public Service works closely with the involved local government jurisdictions and the public. As a part of the siting and permitting process, Public Service develops a comprehensive plan to involve and notify the public. Public Service often develops routing alternatives for a proposed line, if feasible, and seeks public input prior to determining the preferred alternative. The Company also works with landowners near the transmission line corridor and substations to notify them about the proposed project. In addition, the public has opportunities to review and comment on the proposed project during the local jurisdictions' land use review processes.

Public Service believes it employs substantial effort to protect the public's quality of life by minimizing the effects resulting from expansion of the transmission infrastructure. These efforts must be balanced with the responsibility to provide adequate and reliable electric service at just and reasonable rates. The Commission also has the responsibility to balance these interests as Colorado entertains a significant expansion of transmission line development.

G. Transparency and fairness for all market participants, and equitable treatment for all electric industry stakeholders and consumers

As noted above, Public Service and Xcel Energy believe we are compliant with FERC policies regarding Open Access, Order 890 and Order 2003. Recently, FERC amended its regulations in Order No. 890 and adopted reforms to the *pro forma* open access transmission tariff in order to increase transparency in the rules applicable to planning and use of the transmission system. In compliance with FERC Order No. 890, Public Service is continuing to work with other transmission providers in developing transmission planning policies. These FERC requirements are important because the Company must plan and operate transmission systems in a manner that comports with them.

In addition to its participation in WECC, Public Service participates in an organization called WestConnect[9]. As a part of a joint effort with the WestConnect participants, WestConnect has initiated the coordination of certain sub-regional transmission planning activities conducted by CCPG, the Southwest Area Transmission Planning Group (SWAT), and the transmission providers in the Sierra Nevada region in order to produce an annual coordinated transmission plan for the WestConnect footprint[10]. The WestConnect members invite participation in this coordinated planning process from other interested parties in these sub-regions that are not WestConnect members. The coordinated WestConnect sub-regional planning processes are then further coordinated with the Western Electricity Coordinating Council Transmission Expansion Planning Policy Committee (WECC TEPPC) regional transmission planning process. This voluntary, transparent coordinated and open transmission planning process complies with the nine principles for transmission planning now mandatory under FERC Order No. 890[11]. Public Service's participation and experience in these planning organizations helped to support the open stakeholder planning process used to gain input for SB 07-100 implementation.

Pursuant to SB 07-100, Public Service has met a number of times with stakeholders interested in the Company's designation of Energy Resource Zones and related transmission plans. In addition, the Company provided all the materials

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[9] The parties to the WestConnect Amended and Restated Memorandum of Understanding, effective February 14, 2007, are participating in and committing resources to joint efforts to identify, develop and implement cost-effective wholesale market enhancements on a voluntary basis that add value for wholesale users of the Western Grid in transmission accessibility, wholesale market efficiencies and reliability.

[10] See the WestConnect website for a listing of WestConnect initiatives: http://www.westconnect.com/.

[11] See WestConnect Strawman Regarding Compliance with the Nine Planning Principles from Commission Order 890 at http://www.oatioasis.com/PUBLIC SERVICE/PUBLIC SERVICEdocs/WestConnect_890_Strawman_Parts_1_3.pdf.

presented in the stakeholder meeting on a public website. The stakeholder meetings, presentations, and summaries of comments are posted at http://www.rmao.com/wtpp/SB 07-100.html. While SB 07-100 did not require an open stakeholder process for purposes of developing the transmission plans and designation of Energy Resource Zones, Public Service wanted to solicit input from stakeholders regarding both the its designation of Energy Resource Zones and its transmission plans for alleviating transmission constraints in each Zone.

II. COMMISSION AUTHORITY OVER GOALS

The Colorado Commission has considerable authority over transmission CPCN approval, the coordination of generation with transmission planning, retail cost recovery incentives, compliance with state legislative and gubernatorial mandates and goals, minimizing quality of life effects of transmission expansion, and appeals of siting and permitting decisions. FERC has jurisdiction over wholesale rate issues, interstate facilities, and interconnection queues. Appendix G describes the federal-state jurisdictional split of authority, as well as actions taken by FERC, over electric transmission matters. In essence, Public Service is subject to dual regulation over the same system.

III. PRIORITIES OF GOALS AND OTHER AREAS OF INQUIRY THE COMMISSION SHOULD PURSUE

Public Service believes the Commission's primary goals involving transmission issues should be to remove unnecessary obstacles that hinder necessary transmission development and construction. The Commission recognizes the cost-effectiveness of transmission development in Colorado as compared with generation costs, and also knows how crucial additional transmission is to bringing renewable energy capacity in eastern and southern Colorado to load centers.

Public Service has provided comment above on the five year or greater transmission development timeline Public Service experiences in Colorado, in part because of siting and permitting difficulties. Another uncertainty is the length of time needed to obtain a CPCN from the Commission for transmission line projects. The following chart shows the timeline of Public Service's CPCN Applications from 2003 through 2007:

Project	**Docket**	**CPCN Filing**	**Decision**	**RRR Date**	**Rehear-ing**	**Comments**
Steamboat Loop 230kV	03A-068	2/20/2003	4/30/2003	--	--	No Interventions
Denver Terminal-Dakota-Arapahoe 230kV	03A-265E	6/20/2003	8/21/2003	--	--	No Interventions
Midway-Daniels Park 345kV	03A-276E	6/27/2003	11/21/2003			
			1/14/2004			App. Deemed Complete
			11/21/2003	12/11/2003	No	Recommended Decision
			1/14/2004			Final Decision
Chambers 230kV Intertie	03A-329E	7/28/2003	9/19/2003			No Interventions
Comanche 345kV	05A-072E	2/16/2005				
			11/14/2005	12/5/2005		Recommended Decision
			2/7/2006	7/24/2006	Yes	Partial Grant of RRR

			7/3/2006	8/10/2006	Yes	
			9/19/2006			Final Decision
Sandown-Leetsdale 230kV	06A-259E	5/2/2006	1/5/2007	None		
Midway-Daniels Park 345kV	07A-156E	5/1/2007	9/4/2007			Hearings Not Required
Pawnee-Smoky Hill 345kV	07A-421E	10/31/2007	4/28/2008	5/19/2008	Yes	Waiting on Commission decision after 7-9-08 deliberations; rehearing ordered

As can be seen, non-contested applications for transmission line CPCNs can be decided in the span of a few months. However, contested matters such as the Comanche and Pawnee transmission line cases can last much longer. Public Service recognizes that contested matters of necessity take longer to decide because of evidentiary hearings and due process considerations. However, the Commission can streamline the process so that unexpected delays might be avoided.

Recently, the Commission has expressed an interest in just such a streamlined process. As noted in the Introduction above, Public Service believes the Commission can and should provide up-front guidance to participants in the SB07-100 stakeholder process.

IV. APPROPRIATE LEVEL OF INVOLVEMENT OF THE COMMISSION IN GENERATION RESOURCE AND TRANSMISSION FACILITY PLANNING ACTIVITIES, IN-STATE AND REGIONALLY, IN LIGHT OF BUDGETARY AND RESOURCE CONSTRAINTS

Regional participation by commissioners and commission staff is welcomed in the West. Public Service attaches as Appendix H a description of ongoing regional and state activities on transmission matters.

CONCLUSION

Public Service believes that the Commission's inquiry is both timely and useful. The Company expects that there will be increased emphasis on transmission matters and this docket should inform the Commission's consideration of the issues. While the Company does not believe that there will be any particular outcome at this time to many of the issues that the Commission has identified, Public Service is hopeful that the Commission might use this proceeding to develop ways to streamline the CPCN application process by providing Commission input during the SB07-100 and stakeholder planning phases of transmission development.

Dated this 18th day of July, 2008.

Respectfully submitted,

By: ______________________

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CERTIFICATE OF SERVICE

I hereby certify that on this 18th day of July 2008, the original and seven (7) copies of the foregoing PUBLIC SERVICE COMPANY OF COLORADO'S COMMENTS ON THE ISSUES SET FORTH IN DECISION NO. C08-0607 were hand delivered to:

Doug Dean, Director
Colorado Public Utilities Commission
1560 Broadway, Suite 250
Denver, CO 80202

and a copy was hand delivered to:

James Greenwood
Director, Office of Consumer Counsel
1560 Broadway, Suite 200
Denver, CO 80202

Melissa Waddell-Renshaw

APPENDIX A – REGIONAL TRANSMISSION PLANNING

INTRODUCTION

Most of the regional planning that Public Service is involved with occurs through participation in the Colorado Coordinated Planning Group (CCPG). The CCPG is a joint, high voltage transmission system planning forum for the purpose of assuring a high degree of reliability in the planning, development, and operation of the high voltage transmission system in the Rocky Mountain Region, in accordance with the Joint Transmission Access Principles and the Electric Transmission Service Policy Statement, dated December 16, 1991. The CCPG provides the technical forum required to complete reliability assessments, develop joint business opportunities, and accomplish coordinated planning, under the single-system planning concept in the Rocky Mountain Region of the Western Electricity Coordinating Council.

CCPG is one of three Subregional Planning Groups included in WestConnect[1]. The members of WestConnect work collaboratively to assess stakeholder and market needs and to develop cost-effective enhancements to the western wholesale electricity market. WestConnect is committed to coordinating its work with other regional industry efforts to achieve as much consistency as possible in the Western Interconnection. The WestConnect footprint covers Colorado, Arizona, Nevada, and parts of New Mexico, Texas, Wyoming and California. The efforts of CCPG roll up into the WestConnect subregional planning process. Major transmission in the Colorado region is discussed and planned in a collaborative manner with other transmission owners in the region.

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[1] The parties to the WestConnect Amended and Restated Memorandum of Understanding, effective February 14, 2007, are participating in and committing resources to joint efforts to identify, develop and implement cost-effective wholesale market enhancements on a voluntary basis that add value for wholesale users of the Western Grid in transmission accessibility, wholesale market efficiencies and reliability.

The CCPG provides the technical forum required to complete reliability assessments, develop joint business opportunities, and accomplish coordinated planning. As a part of a joint effort with the other WestConnect participants, WestConnect has initiated the coordination of certain sub-regional transmission planning activities conducted by CCPG, the Southwest Area Transmission Planning Group (SWAT), and the transmission providers in the Sierra Nevada region in order to produce an annual coordinated transmission plan for the WestConnect footprint[2]. The WestConnect members invite participation in this coordinated planning process from other interested parties in these sub-regions that are not WestConnect members.

The coordinated WestConnect sub-regional planning processes are then further coordinated with the Western Electricity Coordinating Council and its activities, including those of the Transmission Expansion Planning Policy Committee (WECC TEPPC). In addition to TEPPC, Public Service is an active member of other WECC and planning groups including the Planning Coordination Committee (PCC) and the Technical Studies Subcommittee.

In addition, the Federal Energy Regulatory Commission (FERC) issued Order 890 in early 2007. While covering a variety of issues, it required each jurisdictional transmission owner to file with FERC an Attachment K to its OATT Tariff by December 7, 2007. Attachment K is intended to provide a roadmap of the planning processes used by the transmission owner both for individual company planning (local) as well as for coordinated efforts with other entities in subregional (SWAT and CCPG) and regional (WECC) contexts. Following a posting and a comment period, FERC held a Technical

2 See the WestConnect website for a listing of WestConnect initiatives: http://www.westconnect.com/.

Conference in Denver to receive input on the Attachment K straw posted by transmission owners in the Western Interconnection. FERC staff was complimentary of the efforts of the Western entities to work cooperatively outside of an organized RTO-like structure. Those attachment K documents have been approved by FERC and are part of the Public Service OATT, other participants' OATTs, and the regional planning process.

The following is a description of each regional transmission entity, followed by a discussion of how they work together in regional planning and cooperation.

WECC

WECC has two separate planning groups serving two distinctly different purposes. The planning coordination committee was established by the agreement of the western systems coordinating council dated august 4, 1967. On April 18, 2002, Western Systems Coordinating Council merged with the Southwest Regional Transmission Association and the Western Regional Transmission Association, forming the Western Electricity Coordinating Council (WECC). The planning coordination committee is responsible to:

1. Recommend criteria for the guidance of the members, subject to Board of Directors approval, for adequacy of power supply and for such elements of system design as affect the reliability of the interconnected bulk power systems.

2. Accumulate necessary data and perform regional studies of the operation of the interconnected systems necessary to determine the reliability of the western regional bulk power network.

3. Evaluate proposed additions or alterations in facilities in relation to established reliability criteria.

4. Identify the types and investigate the impact of delay on the timing and availability of power generation and transmission facilities.

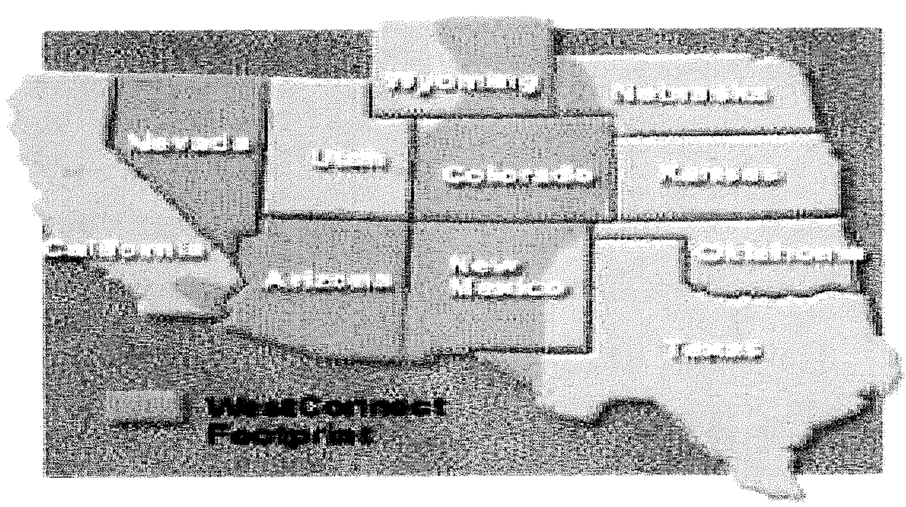
5. Review reports and recommendations prepared by subcommittees and others concerning reliability and adequacy of power supply and forward same with comments and/or recommendations to the Board of Directors in a timely manner.

6. Prepare appropriate reports and maps of planning information for governmental regulatory agencies, reliability councils, and others as required.

The second planning group under WECC is the Transmission Expansion Planning Policy Committee (TEPPC). TEPPC's three main functions include: (1) overseeing database management, (2) providing policy and management of the planning process, and (3) guiding the analyses and modeling for Western Interconnection economic transmission expansion planning. These functions compliment but do not replace the responsibilities of WECC members and stakeholders to develop and implement specific expansion projects.

WestConnect

WestConnect is the next step under the WECC TEPPC for regional planning coordination. The WestConnect footprint covers Colorado, Arizona, Nevada, and parts of New Mexico, Texas, Wyoming, and California:



Transmission providers including Public Service established a WestConnect subregional planning process by signing the WestConnect Project Agreement for Subregional Transmission Planning (STP Agreement).

The STP Agreement established a Planning Management Committee (PMC) made up of one representative of each of the signatory parties. The PMC is tasked with implementation of a subregional planning process that complies with the WestConnect Planning Objectives and Procedures for Regional Planning approved by the WestConnect Steering Committee on August 24, 2006.

The subregional transmission planning is being performed by Southwest Transmission Planning Group (SWAT), the Colorado Coordinated Planning Group (CCPG) and any other subregional transmission planning (STP) groups that forms and makes up the WestConnect planning area. Every year, a ten year integrated regional transmission plan is derived from their efforts that coordinate all transmission plans across the WestConnect planning area.

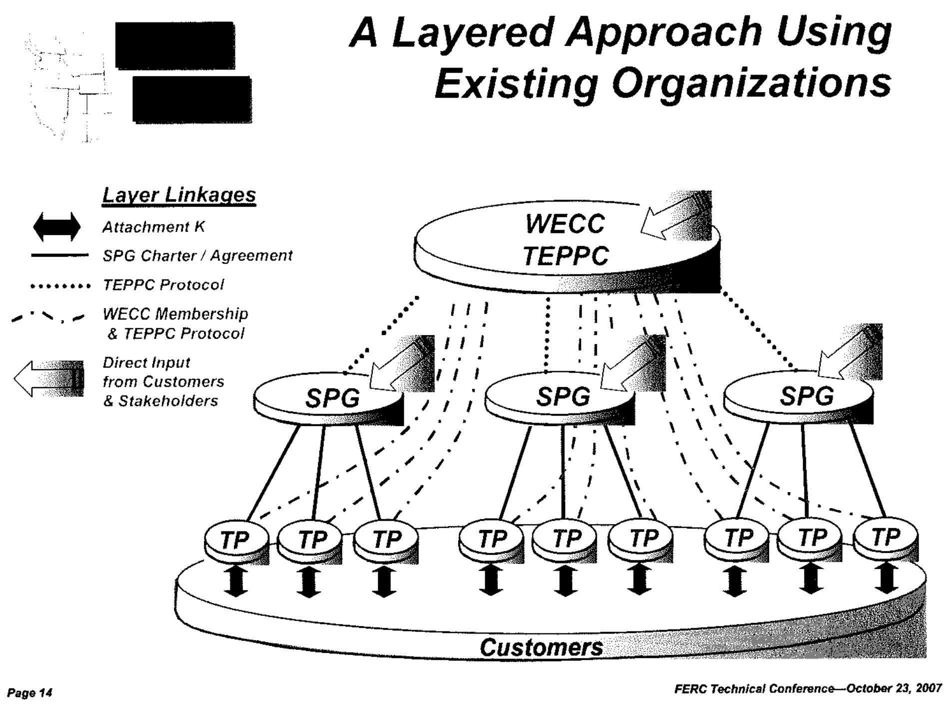
CCPG

The CCPG is a joint, high voltage transmission system planning forum for the purpose of assuring a high degree of reliability in the planning, development, and operation of the high voltage transmission system in the Rocky Mountain Region, in accordance with the Joint Transmission Access Principles and the Electric Transmission Service Policy Statement, dated December 16, 1991. The CCPG provides the technical forum required to complete reliability assessments, develop joint business opportunities, and accomplish coordinated planning, under the single-system planning concept in the Rocky Mountain Region of the Western Electricity Coordinating Council.

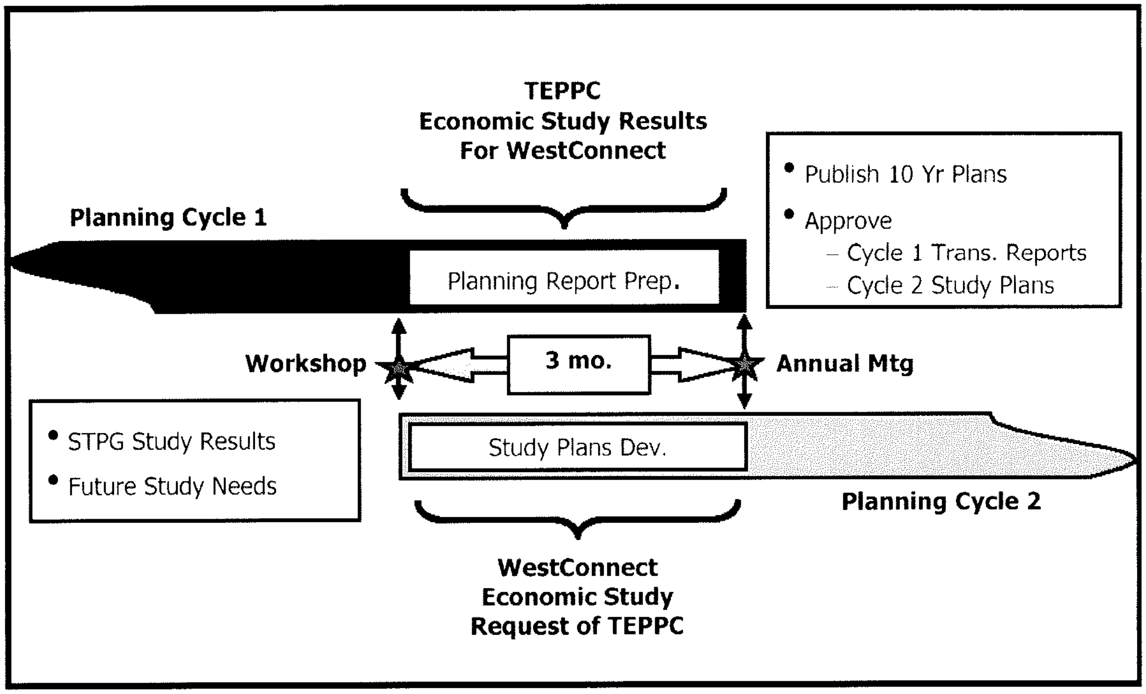
How Are These Entities Connected?

TEPPC analyses and studies focus on plans with west-wide implications and include a high level assessment of congestion and congestion costs. The analyses and studies also evaluate the economics of resource and transmission expansion alternatives on a regional, screening study basis. Resource and transmission alternatives may be targeted at relieving congestion, minimizing and stabilizing regional production costs, diversifying fuels, achieving renewable resource and clean energy goals, or other purposes. The TEPPC depends on technical support from the WECC Standing Committees and subgroups and sub-regional planning groups.

One such subregional planning group is WestConnect. The WestConnect planning process by definition is inclusive of the further subregional planning efforts of CCPG, SWAT and any future STP group that forms within the WestConnect planning area. The WestConnect planning process has been organized to strategically coordinate these subregional planning efforts and encourage the consistent participation of WestConnect STP Agreement members and any additional interested stakeholders or customers. It synchronizes upward to coordinate with WECC regional planning process and its TEPPC regional transmission congestion study efforts. This has been accomplished by a layered approach utilizing existing planning organizations to perform local, subregional and regional planning within the Western Interconnection as depicted in the figure below. The WestConnect subregional planning process consists of activities represented by one Subregional Planning Group (SPG) circle. In effect WestConnect and CCPG activities are merged together on this figure as one SPG but bear in mind, WestConnect also aggregates the work of SWAT and may soon include the Sierra Pacific Nevada Region. Each individual Transmission Provider, such as Public Service is represented as a TP circle.



The WestConnect planning process utilizes a planning cycle concept depicted in the figure below. It assumes two consecutive planning cycles overlap by a given period of time. The overlap of two study cycles offers stakeholders a window of opportunity to be involved and provide input on a variety of levels. It has also been synchronized with the TEPPC planning process to enable a common window of stakeholder input regarding proposed study efforts for the upcoming study cycle. This stakeholder input period is scheduled to occur annually between the months of November and January. It is buttressed by a planning workshop and an annual planning meeting.



Finally, the efforts of CCPG and its member companies including Public Service roll up into the WestConnect subregional planning process. Major transmission in the Colorado region is discussed and planned in a collaborative manner with other transmission owners in the region. The CCPG provides the technical forum required to complete reliability assessments, develop joint business opportunities, and accomplish coordinated planning, under the single-system planning concept in the Rocky Mountain Region.

121 FERC ¶ 61,284
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Xcel Energy Services, Inc. Docket No. ER07-1415-000

ORDER GRANTING INCENTIVES, AND ACCEPTING PROPOSED RATE FORMULA MODIFICATIONS, SUBJECT TO CONDITIONS

(Issued December 21, 2007)

1. On September 28, 2007, Xcel Energy Services, Inc. (Xcel), on behalf of Northern States Power Company of Minnesota (NSP Minnesota) and Northern States Power Company of Wisconsin (NSP Wisconsin) (jointly, the NSP Companies), filed with the Commission pursuant to section 205 of the Federal Power Act (FPA)[1] proposed modifications to the NSP Companies' transmission rate formula under Attachment O of the Midwest Independent Transmission System Operator, Inc.'s (Midwest ISO) Open Access Transmission and Energy Markets Tariff (TEMT). The NSP Companies seek to modify the formula to permit recovery of two types of incentive rate treatments in accordance with Order Nos. 679 and 679-A:[2] (1) 100 percent of prudently incurred Construction Work in Progress (CWIP) in rate base (100 percent CWIP Recovery), and (2) 100 percent of prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond the NSP Companies' control (Abandoned Plant Recovery). The proposed incentive rate treatments would apply to six specific projects that will cost approximately $1 billion (jointly, the NSP Expansion Projects). The NSP Companies also seek to modify their Attachment O rate formula to use projected test year cost inputs, with a true-up mechanism to reflect actual costs. The NSP Companies request an effective date of January 1, 2008.

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[1]16 U.S.C. § 824d (2000).

[2]*Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

2. For the reasons discussed below, we will grant the NSP Companies' request for incentive rate treatment for the NSP Expansion Projects. Moreover, we will accept the NSP Companies' proposed modifications to their Attachment O rate formula, to use projected test year cost inputs subject to conditions, to become effective on January 1, 2008, as requested.

I. Background

A. Description of the NSP Companies

3. The NSP Companies are operating utilities of Xcel, a public utility holding company under the Public Utility Holding Company Act of 2005. NSP Minnesota provides electric service to approximately 1.4 million customers in Minnesota, North Dakota, and South Dakota, while NSP Wisconsin provides electric services to approximately 245,000 customers in portions of western Wisconsin and in the western tip of the Upper Peninsula of Michigan. The NSP Companies are transmission-owning members of the Midwest ISO.[3] The NSP Companies currently collect their annual transmission revenue requirement using the generic rate formula in Attachment O of the Midwest ISO TEMT. Under the generic Attachment O rate formula, the NSP Companies' revenue requirement and rates are updated every June 1 to reflect historic transmission costs and loads for the previous calendar-year, as reported in the NSP Companies' FERC Form No. 1.

B. Description of the NSP Expansion Projects

4. The NSP Companies state that together with other utilities in the region and subject to the oversight of the Midwest ISO, they have been developing plans to upgrade the regional transmission infrastructure.[4] As a result of these planning efforts, the NSP Companies are currently undergoing a major electric transmission expansion program designed to provide the transmission infrastructure necessary to meet state renewable energy generation standards and reliably serve increased loads in the five state region served by the NSP Companies.[5] The NSP Companies state that they expect to invest

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[3] The Commission approved the transfer of functional control of the NSP Companies' transmission system facilities operating at 100 kV and above to the Midwest ISO in *Northern States Power Co.*, 91 FERC ¶ 61,157 (2000).

[4] Transmittal Letter at 1.

[5] *Id.*

approximately $1 billion in the NSP Expansion Projects during the next several years.[6] The projected cost of these projects is greater than the NSP Companies' total 2006 year-end net transmission plant of $928.5 million.[7]

5. The NSP Companies state that the transmission upgrades are needed to accommodate new renewable energy generation resources in the region, particularly wind generation resources.[8] According to the NSP Companies, several states in their region have enacted renewable energy standards in order to encourage the development and use of renewable energy resources.[9] For example, the NSP Companies state that in 2007, Minnesota enacted aggressive renewable energy mandates for electric utilities. For NSP Minnesota, this legislation requires 30 percent of energy generated for their retail customers to come from renewable energy resources, with 25 percent coming from wind energy resources, by the year 2020. Wisconsin has enacted legislation requiring electric providers to increase the amount of renewable energy sold to retail customers to 10 percent by 2015. For NSP Wisconsin, that amount would increase to 12.8 percent by 2016. The NSP Companies assert that their transmission system is located between rich wind energy locations and major Midwest load centers. Therefore, they state, significant new transmission capacity on their system is needed to enable access and deliver new renewable resources to loads in the region.[10]

6. The NSP Companies state that the transmission upgrades are also needed to allow the NSP Companies to continue to reliably serve growing loads in its region. According to the NSP Companies, the demand for electricity supply in their service territories has been growing at a steady rate each year and the demand for transmission capacity has been outstripping supply.

7. The NSP Expansion Projects include two projects the construction of which is proposed to begin in 2008 and four other projects that are part of Group 1 of the CapX 2020 Project.[11] The two projects proposed to begin construction in 2008 are the Buffalo

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[6] *Id.*

[7] *Id.*

[8] *Id.* at 5.

[9] *Id.*

[10] *Id.*

[11] Group 1 of the CapX 2020 Project consists of four 345 and 230 kV projects that make up the first in a series of anticipated large scale transmission expansion projects to be completed as part of the CapX 2020 project initiative, which involves other electric

(continued ...)

Ridge Incremental Generation Outlet Project (BRIGO) and 115/161 kV transmission line upgrade (from 69 kV) between Chisago County, Minnesota and the Apple River substation in Wisconsin (Chisago-Apple). The total estimated cost to the NSP Companies for these two projects is approximately $121 million.

8. The BRIGO project consists of three new 115 kV transmission lines totaling approximately 35-50 miles and several new substations. The purpose of this project is to provide expanded transmission outlet and delivery capability for new wind generation on Buffalo Ridge, which the NSP Companies state is one of the most promising sites for wind generation in the United States. The total estimated cost of this project is $72.5 million. The BRIGO project will have portions going into service in 2008, some portions in 2009, and the balance in 2010, subject to receipt of required routing permits.[12]

9. The Chisago-Apple project consists of a 41-mile, 115/161 kV transmission line upgrade (of an existing 69 kV line) between Chisago County, Minnesota and the Apple River substation owned by Dairyland Power Cooperative in Amery, Wisconsin. Eighteen miles of this line will be in Minnesota and 23 miles will be in Wisconsin. The total estimated cost to the NSP Companies for this project is $48.7 million. This project is proposed to be in service in 2010, subject to receipt of required state regulatory construction and routing approvals.[13]

10. The four projects in Group 1 of the CapX 2020 Project are Twin Cities – Brookings County, Twin Cities – Fargo, Twin Cities – LaCrosse, and Bemidji – Grand Rapids. The total estimated cost to the NSP Companies for the Group 1 CapX 2020 projects is approximately $850 million.

11. The Twin Cities - Brookings County project consists of a 240-mile, 345 kV transmission line between the NSP Brookings County, South Dakota substation and the proposed Hampton substation in the Southeast corner of Twin Cities, as well as a 10-mile, 230 kV segment from a new Hazel Creek substation to a substation in Granite Falls, Minnesota. The line will be located in South Dakota and Minnesota and will increase the deliverability of renewable energy generation resources from southwestern Minnesota

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utilities in the region in the participation in a comprehensive, regional planning initiative. The CapX 2020 project involves eleven electric utilities in the region, including utilities that are not subject to the Commission's jurisdiction as public utilities under the FPA and utilities that are not transmission-owning members of the Midwest ISO.

[12] Transmittal Letter at 7.

[13] *Id.*

and eastern South Dakota to large load centers in eastern Minnesota and western Wisconsin. This project will be jointly constructed and owned by NSP Minnesota and four other utilities in the region. The estimated cost of the project is anticipated to be $600 to $665 million and NSP Minnesota will own a 72 percent share of the project.[14]

12. The Twin Cities – Fargo project consists of a 250-mile, 345 kV transmission line between Fargo, North Dakota and Monticello, Minnesota. The line will be located in North Dakota and Minnesota. The line will address reliability problems in areas in the Red River Valley and northwestern and central Minnesota. This project will be jointly constructed and owned by NSP Minnesota and four other utilities in the region. The estimated cost of the project is $390 to $560 million, and NSP Minnesota will own a 36 percent share of the project.[15]

13. The Twin Cities – LaCrosse project consists of a 150-mile, 345 kV transmission line between the Hampton substation in the southeast corner of the Twin Cities to Rochester, Minnesota and LaCrosse, Wisconsin. The project will cross state boundaries and includes a crossing of the Mississippi River. The project will be jointly constructed and owned by the NSP Companies and four other utilities in the region. The estimated cost of the project is $330 to $360 million, and the NSP Companies will own a 64 percent share of the project.[16]

14. The Bemidji – Grand Rapids project consists of a 68-mile, 230 kV transmission line between Grand Rapids and Bemidji in northern Minnesota. The project will be jointly constructed and owned by NSP Minnesota and four other utilities in the region. The estimated cost of the project is approximately $70 million, and NSP Minnesota will own a 26 percent share of the project.[17]

C. <u>Proposed Incentive Rates</u>

15. The NSP Companies request approval of two incentive-based rate treatments under Order No. 679 for the NSP Expansion Projects: 100 percent CWIP recovery and Abandoned Plant Recovery. The NSP Companies' request for approval of incentives for the NSP Expansion Projects is contingent on the receipt of a Certificate of Need for those projects from the Minnesota Public Utility Commission (Minnesota Commission). With

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[14] *Id.* at 7-8.

[15] *Id.* at 8.

[16] *Id.*

[17] *Id.*

respect to the Abandoned Plant Recovery, the NSP Companies are only proposing a placeholder in their proposed rate formula with a value of zero and will make subsequent section 205 filings for Commission approval to change that value.

16. The NSP Companies state that the requested incentives comply with the standards of Order No. 679 and Commission precedent and submit that, consistent with Order No. 679: (1) the facilities for which they seek incentives satisfy the requirements of FPA section 219 – they either ensure reliability or reduce the costs of delivered power by reducing congestion; (2) the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project – the incentives meet the "nexus" test; and (3) the resulting rates are just and reasonable.[18]

17. The NSP Companies submit that they are entitled to a rebuttable presumption that the requirements of FPA section 219 are satisfied if the NSP Companies receive a Certificate of Need from the Minnesota Commission for the projects.[19] The NSP Companies explain that the Minnesota Commission's process for considering an application for a Certificate of Need considers in detail the need for the project, including a consideration of alternatives and the environmental impacts of the proposed project. According to the NSP Companies, the process requires evaluation of ten factors regarding the project before a Certificate of Need will be issued, including several factors which involve a consideration of reliability and congestion relief. The latter include: (1) benefits of the facility, including its uses to protect or enhance environmental quality, and to increase reliability of energy supply in Minnesota and the region; (2) possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load management programs, and distributed generation; and (3) with respect to a high-voltage transmission line, the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of

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[18] *Id.* at 2.

[19] Pursuant to Order No. 679, and section 35.35(i) of the Commission's regulations, the Commission, in certain cases, will apply a rebuttable presumption where an applicant has shown that its project is needed to ensure reliability or reduces the cost of delivered power by reducing congestion. A rebuttable presumption can be applied to a transmission project that results from a fair and open regional planning process or one that has received construction approval from the appropriate state authority, if the process requires that a project ensures reliability or reduces the cost of delivered power by reducing congestion. 18 C.F.R. § 35.35(i) (2007).

the transmission system or lower costs for electric consumers in Minnesota.[20] While several of the projects will be located in more than one state, the NSP Companies state that each of the multi-state projects include substantial facilities located in Minnesota, and, therefore, the NSP Companies will need to obtain a Certificate of Need from the Minnesota Commission for all of the NSP Expansion Projects. Thus, the common denominator for all the NSP Expansion Projects is the need for a Certificate of Need from the Minnesota Commission.[21]

18. In establishing the nexus between the incentive sought and the investment made, the NSP Companies state that allowing a 100 percent CWIP Recovery on the NSP Expansion Projects will eliminate disincentives to completing the projects in several ways.[22] First, it will reduce stresses on cash flows for the NSP Companies.[23] Second, it will relieve downward pressure on the NSP Companies' credit rating that could be caused by the NSP Expansion Projects.[24] Third, it should help the NSP Companies meet their

[20] Transmittal Letter at 17-18. The other 7 factors are: (1) the accuracy of the long-range energy demand forecasts on which the necessity for the facility is based; (2) the effect of existing or possible energy conservation programs under state statutes or other federal or state legislation on long-term energy demand; (3) the relationship of the proposed facility to overall state energy needs, as described in the most recent state energy policy and conservation report, or, in the case of a high-voltage transmission line, the relationship of the proposed line to regional energy needs, as presented in the transmission plan submitted under the biennial State Transmission Plan statute; (4) promotional activities that may have given rise to the demand for this facility; (5) the policies, rules, and regulations of other state and federal agencies and local governments; (6) any feasible combination of energy conservation improvements that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically; and (7) whether the applicant or applicants are in compliance with applicable provisions of state statutes pertaining to state renewable energy objectives and transmission needed to support renewable resources. *Id.*

[21] Ex. No. XES-24 at 12-13.

[22] Transmittal Letter at 25.

[23] *Id.* The NSP Companies' application includes an affidavit of the Vice President and Treasurer of the NSP Companies with analysis showing that they expect to face a negative cash flow position while undergoing the projects.

[24] *Id.*

financial goals, which might be threatened by the NSP Expansion Projects.[25] Finally, it will not have an adverse impact on the electric transmission rates for the NSP Companies' customers.[26]

19. The NSP Companies state that the Abandoned Plant Recovery will remove a potential disincentive to completion of the NSP Expansion Projects by eliminating the risk that shareholders may have to bear the costs of transmission projects that are cancelled for reasons outside the NSP Companies' control.[27] The NSP Companies state that there are several ways in which one or more of the NSP Expansion Projects could be cancelled for reasons outside the NSP Companies' control.[28] For example, a major purpose of the projects is to provide transmission capacity for potential new renewable generation resources on the NSP Companies' system. While the NSP Companies expect that these new renewable resources will be developed, the binding commitments to interconnect and transmit this power have not all been made. Therefore, there is a risk that some of these projects may be cancelled or significantly modified due to decisions by renewable generators to cancel or relocate. Further, the NSP Companies explain, five of the six projects are being constructed jointly with neighboring utilities, including utilities that are not subject to the Commission's jurisdiction as public utilities and/or are not members of the Midwest ISO. The NSP Companies state that it is possible that those partners may change or revise their plans, which could have an impact on the NSP Expansion Projects. Also, the Midwest ISO has substantial planning authority regarding transmission planning, and there is some risk that some of the NSP Expansion Projects could be cancelled or revised for reasons identified through the regional planning process. Finally, the NSP Companies explain, the projects require routing and other regulatory approvals from the various state commissions, and potential opposition to routing of the transmission projects may present the risk that a project might be abandoned for reasons outside of the NSP Companies' control.

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[25] *Id.* at 25-26. The NSP Companies' financial objectives include maintaining financial integrity by improving corporate credit ratings and senior unsecured debt ratings and continuing to provide reasonably-priced electric and natural gas services to their customers. They state that 100 percent CWIP Recovery will promote these objectives by enabling them to maintain lower borrowing costs as they complete the projects.

[26] *Id.* at 26.

[27] *Id.*

[28] Ex. No. XES-9 at 31-32.

20. The NSP Companies state that the two proposed incentives are consistent and compatible.[29] The NSP Companies state that they are not seeking any return on common equity (ROE) based incentives. Instead, the NSP Companies explain that they are seeking two incentives that serve the same purposes: to reduce risks presented by the transmission projects and to remove potential obstacles to construction of the projects.[30] The NSP Companies state that in Order No. 679, the Commission found that these two incentives are similar.

21. The NSP Companies state that the resulting rates will be just, reasonable and not unduly discriminatory.[31] With respect to the 100 percent CWIP Recovery incentive, the NSP Companies state that the Commission has recognized that the initial inclusion of CWIP in rate base affects only the timing of the cost recovery, not the level of cost recovery.[32]

22. Additionally, although the NSP Companies are not specifically requesting incentive ratemaking treatment for employing innovative transmission technologies, they include a technology statement for the NSP Expansion Projects, as required by Order No. 679.[33] Specifically, the NSP Companies state that, among other things, the NSP Expansion Projects will use "advanced transmission technologies" including: micro-processor based protective relays instead of solid-state or electro-mechanical relays; digital fault recorders, PLC-based control and annunciation, rather than reliance on control switches, light boxes and discrete relays; tubular steel structures rather than lattice-type structures; fiber-optic based communication where cost effective; and advanced conductor designs.[34]

23. The NSP Companies note when determining whether the nexus requirement is satisfied, it is not clear whether it is necessary to show that a project or group of projects is "routine" in cases where the applicant does not seek any ROE-based incentives. The NSP Companies state that this aspect of the nexus test should not apply to their request for incentives because they are not seeking any ROE-based incentives. Nevertheless, the

[29] Transmittal Letter at 28.

[30] *Id.*

[31] *Id.*

[32] *Id.* at 29 (citing Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 38).

[33] Transmittal Letter at 23 (citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 302).

[34] *Id.* at 23-24. *See also* Ex. No. XES-8 at 29-31.

Accordingly, the NSP Companies state, this would improve their cash flow position and promote their ability to carry out their transmission expansion program.[43] The NSP Companies state that the proposed formula modifications to use projected costs with subsequent true-up follow closely revisions to the Attachment O rate formulas of other Midwest ISO transmission owners that the Commission has approved.[44]

26. The NSP Companies also include provisions in their proposed Attachment O rate formula to allow recovery of the two incentive-based rate treatments for the NSP Expansion Projects that they seek under Order No. 679: 100 percent CWIP Recovery and Abandoned Plant Recovery. The NSP Companies state that the Midwest ISO's generic Attachment O rate formula does not contain line items to allow the NSP Companies to recover these two requested incentives, but the proposed forward looking Attachment O rate formula will allow those incentives.[45]

27. The NSP Companies state, however, that they are only seeking approval to add to the rate formula a placeholder in the line items for potential Abandoned Plant Recovery.[46] The NSP Companies state that they will maintain a value of zero for these lines in the rate formula template until the NSP Companies receive Commission approval to recover costs for the Abandoned Plant Recovery incentive through a separate section 205 filing. With respect to 100 percent CWIP Recovery, CWIP associated with each project will only be included in rate base beginning in the month in which a Certificate of Need for the project is granted by the Minnesota Commission.[47]

28. The NSP Companies state that they are not seeking to change the existing Commission-approved ROE of 12.38 percent.[48]

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[43] *Id.*

[44] *Id.* at 14-15 (citing *Michigan Elec. Transmission Co.,* 117 FERC ¶ 61,314 (2006), *order on reh'g*, 118 FERC ¶ 61,139, *order on compliance*, 119 FERC ¶ 61,203 (2007) (*Michigan Electric*); *International Transmission Co.,* 116 FERC ¶ 61,036 (2006) (*International Transmission*); *American Transmission Co.,* 97 FERC ¶ 61,139 (2001) (*ATC*)).

[45] *Id.* at 10.

[46] *Id.*

[47] Ex. No. XES-4 at 13.

[48] Ex. No. XES-1 at 18.

II. Notice of the Filing and Responsive Pleadings

29. Notice of the NSP Companies' filing was published in the *Federal Register*, 72 Fed. Reg. 57,549 (2007), with interventions and protests due on or before October 19, 2007. On October 10, 2007, Central Minnesota Municipal Power Agency (CMMPA) and the Midwest Municipal Transmission Group (MMTG) filed a motion requesting an extension of time to file comments until October 26, 2007, which the Commission granted.

30. Motions to intervene were timely filed by Missouri River Energy Services, Dairyland Power Cooperative, the Midwest Stand-Alone Transmission Companies,[49] Wisconsin Public Power Inc., the Midwest ISO Transmission Owners,[50] and Southern Minnesota Municipal Power Agency. Consumers Energy Company filed a motion to intervene out-of-time.

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[49] For purposes of this filing, the Midwest Stand Alone Transmission Companies include American Transmission Company LLC (ATCLLC), International Transmission Company (International Transmission), and Michigan Electric Transmission Company, LLC (Michigan Electric).

[50] For purposes of this filing, the Midwest ISO Transmission Owners include: Ameren Services Company, as agent for Union Electric Company d/b/a AmerenUE, Central Illinois Public Service Company d/b/a AmerenCIPS; Central Illinois Light Co. dba AmerenCILCO, and Illinois Power Company d/b/a AmerenIP; Alliant Energy Corporate Services, Inc. on behalf of its operating company affiliate Interstate Power and Light Company (f/k/a IES Utilities Inc. and Interstate Power Company); American Transmission Systems, Incorporated, a subsidiary of FirstEnergy Corp.; City of Columbia Water and Light Department; City Water, Light & Power; Duke Energy Shared Services for Duke Energy Ohio, Inc., Duke Energy Indiana, Inc., and Duke Energy Kentucky, Inc.; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; Michigan Public Power Agency; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.

31. Minnesota Municipal Power Agency filed a motion to intervene and protest. The Municipal Intervenors[51] filed a motion to intervene and comments. CMMPA and MMTG filed a motion to intervene and comments in support of the NSP Companies' proposal and a request for a declaratory order seeking authorization for incentive rate treatment for certain of their own transmission projects in their Attachment O rate formulas under the Midwest ISO TEMT.

32. On November 5, 2007, Xcel, on behalf of the NSP Companies, filed a motion for leave to intervene and answer.

33. On November 13, 2007 the Municipal Intervenors filed a response to Xcel's motion for leave to intervene and answer.[52]

34. Otter Tail Power Company (Otter Tail) filed a motion for extension of time to respond to CMMPA/MMTG's request for declaratory order. Otter Tail requests that the Commission grant an extension of time to December 3, 2007, or, in the alternative, that the Commission sever CMMPA/MMTG's request from this proceeding.

35. Great River Energy filed comments in support of Otter Tail's motion for extension of time. CMMPA/MMTG filed a motion for leave to answer and answer to Otter Tail's motion and Great River Energy's comment. Otter Tail and CMMPA/MMTG filed a motion for extension of time. NSP Companies filed a response to Otter Tail and CMMPA/MMTG's motion for extension of time. CMMPA/MMTG filed corrections to testimony attached to its motion to intervene and comments and request for declaratory order.

A. Comments

36. CMMPA and MMTG state that they support the NSP Companies' proposals and that the requested incentives are limited and tailored to support major transmission construction that is required to improve reliability and to relieve congestion in the region. CMMPA and MMTG also state that they are 3 percent co-owners of the Twin Cities-Brookings County project. As co-owners, CMMPA and MMTG seek similar rate formula and incentive rate treatment that is requested by the NSP Companies for the

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[51] For purposes of this filing, Municipal Intervenors include the following cities and villages: Bangor, Cadott, Cornell, Medford, Rice Lake, and Spooner, Wisconsin.

[52] The City of Barron, since their first comment, was added as part of the Municipal Intervenors.

reasons given by the NSP Companies in their filing, to establish CMMPA's and MMTG's revenue requirements and rates under the Midwest ISO TEMT. They also seek this rate treatment for other similar projects.

37. Municipal Intervenors state that they are concerned that the NSP Companies' proposal to use projected test year cost inputs does not provide for adequate review procedures. Municipal Intervenors note that the NSP Companies propose to provide their customers with information on their annual updates to the Attachment O rate formula, and that the NSP Companies state they will hold a customer meeting to discuss the calculations by October 31 of each year to answer questions. However, Municipal Intervenors contend that it is not yet clear whether these procedures will provide for a sufficiently detailed information exchange between the NSP Companies and their customers, or for adequate time and procedures for follow-up questioning and informal discovery. Municipal Intervenors argue that in the event that errors are made in the NSP Companies' implementation of formula inputs, there appears to be no mechanism for ensuring that corrections can be made. Municipal Intervenors propose that the Commission establish informal settlement proceedings so that the NSP Companies and their customers can develop adequate procedures for information exchange and review.

38. MMPA argues that the NSP Companies' proposal to true-up budgeted transmission costs to actual transmission costs provides a guarantee of cost recovery even though the FPA provides for a regulated utility to "be allowed a reasonable opportunity to recover its expenses, including a fair and reasonable return on investment."[53] MMPA contends that the NSP Companies' true-up proposal eliminates the risk of under-recovery of costs due to weather abnormalities and reduced loads due to business cycle changes. Additionally, MMPA argues that the NSP Companies' request for a 100 percent return on their CWIP once a Certificate of Need has been issued for a project, will increase cash flows and reduce business risk for the NSP Companies.[54] MMPA argues that the NSP Companies' proposal changes the basic regulatory paradigm by reducing business risk without changing the allowed ROE. MMPA argues that allowing the NSP Companies to add the proposed true-up mechanism and incentive rate treatment to their rate formula without reducing their ROE to properly reflect the greatly reduced business risk will result in unjust and unreasonable transmission rates.

39. MMPA also argues that the NSP Companies' existing 12.38 percent ROE was established in a prior filing where there were no risk reducing true-ups for costs and

[53] MMPA's Protest at 4.

[54] *Id.*

billing determinants. MMPA contends that allowing the NSP Companies to add the proposed true-up mechanisms to their rate formula without reducing their ROE to properly reflect the greatly reduced business risk will result in unjust and unreasonable transmission rates. Additionally, MMPA argues that the NSP Companies' request for a 100 percent return on their CWIP once a Certificate of Need has been issued for a project, will increase cash flows and reduce business risk for the NSP Companies.

40. MMPA also argues that the NSP Companies' proposal to continue to use the 12.38 percent ROE currently authorized for all Midwest ISO transmission owners places MMPA in a "price squeeze." According to MMPA, Xcel recently completed a retail rate increase filing in Minnesota state proceedings in which the Minnesota Commission allowed a 10.54 percent ROE and a 8.81 percent weighted after-tax cost of capital.[55] If the Commission approves the amended Attachment O rate formula as the NSP Companies' request, the rate formula would yield a 12.38 percent cost of common equity and a 9.92 percent after-tax weighted cost of capital. MMPA argues that there would be a difference of 101 basis points on an after tax basis. MMPA believes that the difference in the NSP Companies' rates of return between the bundled retail rate and wholesale transmission rate will produce a significantly lower cost of transmission for the NSP Companies' retail customers compared to the rates paid by MMPA members. This effect, according to MMPA, places MMPA at a competitive disadvantage by putting it in a price squeeze and violates the Commission's Order No. 888 "comparability standard,"[56] which requires the transmission provider to offer third parties access to transmission on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's use of its system.

B. <u>The NSP Companies' Answer</u>

41. The NSP Companies state that none of the comments filed in the proceeding raise any reason for rejecting, modifying, suspending or setting for hearing their filing.

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[55] *Id.* at 5.

[56] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

42. With respect to CMMPA/MMTG's answer and request for declaratory order, the NSP Companies state that while they appreciate the support of CMMPA/MMTG concerning the NSP Companies' filing, they note that the request for declaratory order was submitted by CMMPA/MMTG alone, and neither Xcel nor the NSP Companies solicited CMMPA/MMTG's filing, nor did they participate in the preparation of it or review it. Further, they do not take a position on the merits of CMMPA/MMTG's filing or the requests contained therein at this time. The NSP Companies state in the event that the Commission finds that CMMPA/MMTG's request may prejudice or adversely impact the NSP Companies' request that its filing be accepted without suspension or hearing and with an effective date of January 1, 2008, or may result in an unduly complicated record or proceeding, the Commission should sever CMMPA/MMTG's request for a declaratory order and consider it in a separate docket that is not linked to this proceeding.

43. The NSP Companies dispute the Municipal Intervenors' assertions that the NSP Companies' procedures for customer review of the annual rate estimates are not sufficiently detailed and provide no mechanism for ensuring that corrections can be made. The NSP Companies state that the Municipal Intervenors have failed to justify their request that the Commission initiate informal settlement proceedings. The NSP Companies state that the customer review and information procedures proposed in their filing are similar to and were modeled after customer review and information procedures that the Commission approved in *Michigan Electric* and *International Transmission*. The NSP Companies state that the Municipal Intervenors do not explain why the procedures proposed by the NSP Companies are not sufficiently detailed. They state that the NSP Companies have already used the customer review and information procedures for the estimates that are proposed to take effect on January 1, 2008. The NSP Companies state that they held a customer meeting on October 11, 2007, to discuss the 2008 estimated costs and that the NSP Companies were able to answer all of the customers' questions regarding the 2008 estimates. The NSP Companies further state that a representative from the Municipal Intervenors was in attendance. For these reasons, the NSP Companies state that the Municipal Intervenors' request for informational settlement discussion to discuss these procedures is unsupported and would appear to serve no useful purpose.

44. The NSP Companies argue that the MMPA's arguments are inadequately supported and without merit. They argue that MMPA's objection to the proposed true-up mechanism is contrary to Commission precedent and that the Commission has accepted virtually identical true-up mechanisms for Michigan Electric and International Transmission, two other Midwest ISO transmission owners. The NSP Companies also state that while MMPA claims that the proposed true-up mechanism "provides a guarantee of recovery" and "eliminates the risk of under-recovery" MMPA fails to

acknowledge that it will also assure that the NSP Companies cannot over-recover from their customers because any deviation between estimates and the actual cost will be corrected with interest through the true-up.

45. The NSP Companies state that MMPA's claim that the Commission should lower the NSP Companies' existing ROE due to alleged changes in business risk is wholly unsupported. The NSP Companies state that in their filing they proposed no change to their currently approved ROE contained in the NSP Companies' existing rate formula and that when a party seeks to alter aspects of utility rate structure that the utility did not propose to change under section 205 of the FPA, that party must meet its burden of proof under section 206 of the FPA. The NSP Companies further state that if MMPA wants the Commission to lower the NSP Companies' existing ROE, it has the burden to prove that the existing ROE is unjust and unreasonable. But, the NSP Companies contend, MMPA provides no testimony and no analysis that might demonstrate that the existing ROE has become unjust and unreasonable, and MMPA's "bald allegations" are insufficient to support a contention that an existing rate has become unjust and unreasonable.[57]

46. The NSP Companies state that MMPA's contention that the difference between the NSP Companies' Commission-approved ROE and state-approved ROE violates the "comparability" principle is unsupported and contrary to Commission precedent. The NSP Companies state that MMPA conducts no analysis to show that the rates for retail customers are not comparable, other than pointing to a single element of the rate structure in a single state, Minnesota. Further, the NSP Companies state, MMPA cites no case where the Commission has held that a different retail and wholesale ROE violates the comparability principle. The NSP Companies state that it is well-settled that the Commission has exclusive jurisdiction over wholesale rates and is not obligated to rely on rates set by the states.

47. The NSP Companies state that MMPA's assertions that the difference between the Commission-approved and state-approved ROEs results in an anticompetitive "price squeeze" is unsupported and without merit. The NSP Companies state that under the Commission's regulations, a party arguing that there is a "price squeeze" must make a *prima facie* showing that an unlawful price squeeze exists. The NSP Companies state that MMPA's protest does not attempt to make a *prima facie* showing of the existence of

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[57] The NSP Companies further state that the Commission rejected virtually identical claims in *Michigan Electric* and *International Transmission*, where the Commission stated that such assertions regarding changes in the transmission owner's business risk profile were "too general and unsupported" to warrant a section 206 investigation.

an unlawful price squeeze and, under well-settled precedent, the Commission will dismiss price squeeze allegations where the alleging party fails to make a *prima facie* showing.

C. Municipal Intervenors' Response

48. The Municipal Intervenors state that the NSP Companies overstate the holdings of the Commission in *Michigan Electric* and *International Transmission*. They state that neither *Michigan Electric* or *International Transmission* clearly identify the scope of the information or the level of detail that must be provided to interested parties regarding the implementation of the Attachment O rate formula. Additionally, the Municipal Intervenors state, in *Michigan Electric* and *International Transmission*, the Commission approved the submission of projected revenue requirements and estimated data 60 days in advance of the proposed customer meeting to discuss the calculation - not the 30 days advance distribution proposed by the NSP Companies and not the distribution 13 days in advance of the customer meeting this year to discuss the 2008 estimates. The Municipal Intervenors further state that just because the NSP Companies answered customers' questions regarding the 2008 estimates, does not mean that the review protocol could not be improved through informal settlement proceedings nor does the availability of the complaint procedure under section 206 of the FPA make informal settlement proceedings requested by the Municipal Intervenors a needless exercise. They further state that inviting informal settlement proceedings is a way to avoid costly and time-consuming litigation and, moreover, the Municipal Intervenors' request keeps the onus on the NSP Companies to maintain transparency and carry the burden of implementing just and reasonable rate formula adjustments.

III. Discussion

A. Procedural Matters

49. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[58] the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. In addition, we will grant the unopposed, late intervention of Consumers Energy Company in view of the early stage of the proceeding and the absence of undue prejudice or delay.

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[58] 18 C.F.R. § 385.214 (2007).

50. Rule 213(a) of the Commission' Rules of Practice and Procedure[59] prohibits an answer to a protest, unless otherwise permitted by the decisional authority. We will accept the NSP Companies' answer and Municipal Intervenors' response because they have provided information that assisted us in our decision-making process.

51. As discussed below, we will deny CMMPA/MMTG's request for declaratory order without prejudice. Therefore, we will also deny Otter Tail's motion for extension of time, and reject Great River Energy's comments in support of that motion, CMMPA/MMTG's answer, Otter Tail and CMMPA/MMTG's motion for extension of time, NSP Companies' response, and CMMPA/MMTG's corrections to its motion to intervene and comments and request for declaratory order.

B. Incentives

1. Section 219 Requirements

52. In the Energy Policy Act of 2005 (EPAct 2005), Congress addressed the allowance of incentive-based rate treatments for new transmission construction.[60] Specifically, section 1241 of the EPAct 2005 added a new section 219 to the FPA directing the Commission to establish, by rule, incentive-based (including performance-based) rate treatments. The Commission issued Order No. 679, which set forth processes by which a public utility could seek transmission rate incentives pursuant to section 219, including the incentives requested here by the NSP Companies.

53. The NSP Companies submit that the NSP Expansion Projects qualify for a rebuttable presumption that they meet the requirements of FPA section 219 if a Certificate of Need for the projects is granted by the Minnesota Commission for each of these projects. As stated above, Order No. 679, as modified by Order No. 679-A, provides that a rebuttable presumption can be applied to a transmission project that results from a fair and open regional planning process or one that has received construction approval from the appropriate state authority, if the process requires that a project ensures reliability or reduces the cost of delivered power by reducing congestion.[61] In this case, the NSP Companies have not yet received a Certificate of Need from the Minnesota Commission for each of the projects. In Order No. 679, the Commission indicated that it would consider a request for incentive treatment for a

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[59] *Id.* § 385.213(a)(2).

[60] *See* Pub L. No. 109-58, 119 Stat 594, 961 (2005).

[61] 18 C.F.R. § 35.35(i) (2007).

project which is still undergoing consideration in a regional planning process, but may make any requested rate treatment contingent upon the project being approved under the regional planning process.[62] We find that it is appropriate to consider projects undergoing the state approval process in the same way because the regional planning and state approval processes are similarly treated in applying a rebuttable presumption under Order Nos. 679 and 679-A. The NSP Companies' proposal is consistent with this approach in that the incentives will not be included in rates until a Certificate of Need is received from the Minnesota Commission. In addition, the NSP Companies have demonstrated that the Minnesota Commission considers whether the project ensures reliability or reduces congestion costs in evaluating an application for a Certificate of Need. Therefore, we find that the NSP Expansion Projects qualify for a rebuttable presumption that they meet the requirements of FPA section 219 if they receive a Certificate of Need from the Minnesota Commission.

2. **The Nexus Requirement**

54. In addition to satisfying the section 219 requirement, an applicant for an incentive rate must show that there is a nexus between the incentive sought and the investment being made. The Commission stated that in evaluating whether an applicant has satisfied the required nexus test, the Commission will examine the total package of incentives being sought, the interrelationship between any incentives, and how any requested incentives address the risks and challenges faced by the project.[63] Applicants must provide sufficient explanation and support to allow the Commission to evaluate the incentives. In addition, the Commission has clarified that it retains the discretion to grant incentives that promote particular policy objectives unrelated to whether or not a project presents specific economic risks or challenges.[64]

55. In Order No. 679-A, the Commission clarified that its nexus test is met when an applicant demonstrates that the total package of incentives requested is "tailored to address the demonstrable risks or challenges faced by the applicant."[65] By its terms, this nexus test is fact-specific and requires the Commission to review each application on a

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[62] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at n.39.

[63] 18 C.F.R. § 35.35(d); Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 26. *See also* Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 21 ("By this we mean that the incentive(s) sought must be tailored to address the demonstrable risks and challenges faced by the applicant in undertaking the project.").

[64] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at n.37.

[65] *Id.* P 40.

case-by-case basis. Notably, the Commission chose not to adopt a list of criteria or characteristics that must be met by every applicant before an incentive would be approved. The Commission recognized that it would be impossible to identify every conceivable challenge or risk faced by an applicant, or to develop *a priori* a menu of incentives that would or would not be appropriate given a particular set of risks and challenges. Furthermore, the Commission stated that it would "look favorably on an incentive request that includes public power joint ownership."[66]

56. We find that the NSP Companies have demonstrated that the NSP Expansion Projects are not routine construction projects and present special risks. As discussed below, we find that each incentive sought by the NSP Companies is designed to address a distinct set of the risks associated with the NSP Expansion Projects. Thus, we find that the total package of incentives is reasonable.

i. <u>100 Percent CWIP Recovery</u>

57. In Order No. 679, the Commission established a policy that allows utilities to include, where appropriate, 100 percent of prudently-incurred transmission-related CWIP in rate base.[67] It noted that this rate treatment will further the goals of section 219 by providing up-front regulatory certainty, rate stability, and improved cash flow for applicants, thereby reducing the pressures on their finances caused by investing in transmission projects.[68] As discussed below, we find that the NSP Companies have shown a nexus between the proposed CWIP incentive and their investment in the NSP Expansion Projects.

58. Consistent with Order No. 679, we find that authorizing 100 percent of CWIP treatment for the NSP Expansion Projects would enhance the NSP Companies' cash flow, reduce interest expense, assist the NSP Companies with financing, and improve the NSP Companies' coverage ratios used by rating agencies to determine credit quality by replacing non-cash Allowance for Funds Used During Construction (AFUDC) with cash earnings. This, in turn, will reduce the risk of a down-grade in the NSP Companies' corporate credit and debt ratings.

59. The NSP Companies demonstrate that due to the size and the scope of the proposed projects, there is an increased risk to their credit rating. The NSP Companies

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[66] Order No. 679-A, FERC Stats. & Regs. ¶ 31,245 at P 102.

[67] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 29, 117.

[68] *Id.* P 115.

demonstrate that the NSP Expansion Projects have considerably long lead times, with final in-service dates largely occurring in 2012 or later, and that the overall magnitude of investment in the projects is significant ($1 billion, compared to the NSP Companies' current net investment in transmission plant of $925 million). These factors are comparable to those that the Commission has taken into consideration in authorizing CWIP in rate base for other utilities.

60. The increased cash flow from the CWIP incentive is used in calculating a utility's coverage ratio,[69] a ratio that Standard and Poor's considers in deciding what credit rating to give a utility.[70] NSP Minnesota's corporate credit rating is BBB, two notches above non-investment grade, and its senior unsecured debt rating is BBB-, the lowest investment rating. Without CWIP in rate base, the NSP Companies state that they will have negative cash flows, with a converse increase in interest expenses from debt and a potential negative impact to their credit rating and ability to procure debt at a low cost.[71] The NSP Companies provide information showing the correlation between corporate credit ratings and short-term credit ratings. This data shows that a down-grade in NSP Minnesota's corporate credit rating by one notch to BBB- would likely lead to a downgrade in its commercial paper rating from A-2 to A-3. Such a downgrade would limit NSP Minnesota's access to the low cost commercial paper market because money market funds, which are the primary investors in commercial paper, are restricted by the Securities and Exchange Commission from buying commercial paper rated below A-2.

61. For the reasons discussed above, the Commission finds that the NSP Companies should be granted the 100 percent CWIP Recovery incentive for the NSP Expansion Projects upon their receipt of a Certificate of Need from the Minnesota Commission.

ii. Abandoned Plant Recovery

62. In Order No. 679, the Commission found that abandoned plant recovery is an effective means to encourage transmission development by reducing the risk of non-recovery of costs.[72] We will grant the NSP Companies' request for recovery of 100 percent of prudently-incurred costs associated with abandonment of NSP Expansion

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[69] A coverage ratio is a measurement of a utility's ability to repay debt obligations.

[70] *See* Standard and Poor's Encyclopedia of Analytical Adjustments for Corporate Entities, pub. July 9, 2007, www.standardandpoors.com/ratingsdirect.

[71] The NSP Companies compare the cash flow impacts of CWIP in rate base to revenues without the incentive. *See* Ex. XES-18 at 2, lines 25-44.

[72] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 163.

Projects, provided that the abandonment is a result of factors outside the control of the NSP Companies which must be demonstrated in a subsequent section 205 filing for recovery of abandoned plant.[73] When the NSP Companies make a section 205 filing, they will bear the burden of supporting their decision to abandon the project for which they are seeking recovery of abandoned plant costs.

63. We find that the NSP Companies have shown, consistent with Order No. 679, a nexus between the recovery of prudently-incurred costs associated with abandoned transmission projects and their planned investment. Besides their scope, size, and long lead-times, the projects present special risks because they require approvals from multiple jurisdictions, are dependent upon continued participation by multiple owners, and are subject to potential cancellation or modification through the Midwest ISO regional planning process. Accordingly, the Commission finds that the NSP Companies should be granted the Abandoned Plant Recovery incentive for the NSP Expansion Projects.

iii. <u>Other Requirements for CWIP Recovery</u>

64. Pursuant to Order No. 679 and the Commission's regulations,[74] a company must propose accounting procedures that ensure that customers will not be charged for both capitalized AFUDC and corresponding amounts of CWIP in rate base. To satisfy this requirement the NSP Companies state that they will implement a "pre-funded" AFUDC calculation, which will assure that future rate base calculations are correct, the income statement and balance sheet are correct for financial statement presentation, and that the NSP Companies will have complied with the Commission's rules regarding the recording of AFUDC to construction.[75] Specifically, the NSP Companies state that AFUDC will be recorded to income and CWIP during the construction phase and a pre-funded AFUDC calculation will be simultaneously made on CWIP projects that are included in rate base in the projected rate formula.[76] The NSP Companies state that the pre-funded AFUDC, which they intend on recording in a miscellaneous deferred credit account, is an offset to the plant in service asset when the balances are combined. The NSP Companies explain that as depreciation is taken on the plant asset, the miscellaneous deferred credit will be amortized over the same time and at the same rate. Furthermore, the NSP Companies state that in future rate formula calculations, the transmission assets will be included in rate base offset by the pre-funded AFUDC miscellaneous deferred credit balance, which

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[73] *Id.* P 163, 165-66.

[74] 18 C.F.R. § 35.25 (2007) (recovery of CWIP in rate base).

[75] Referring to Testimony of Deborah A. Blair, Ex. No. XES-4 at 13-14.

[76] *Id.* at 13, lines 12-15.

the NSP Companies state will assure that there is no double recovery of financing cost incurred during construction.

65. While the NSP Companies' filing explains its rate mechanism to avoid double recovery, it lacks certain details necessary for the Commission to conclude that double recovery will indeed be avoided. For example, the filing does not provide the specific FERC accounts the NSP Companies will use to initially record pre-funded AFUDC or the accounts to be used to amortize the pre-funded AFUDC once the project is in service. The filing is also silent on the accounting procedures to be used to ensure the pre-funded AFUDC calculation includes all costs in CWIP receiving the rate base incentive.

66. To correct the deficiencies in its proposal, the NSP Companies are hereby ordered to submit, in a compliance filing to be made within 30 days of this order, proposed journal entries reflecting all the accounting entries related to the projects along with narrative explanations describing the basis for the accounting entries, including a description of procedures and controls that the NSP Companies will implement to prevent improper capitalization.[77]

67. To comply with the requirement that an applicant seeking CWIP recovery in rate formulas make an annual filing with the Commission, the NSP Companies state that they will annually file the FERC Form No. 730 report.[78] In addition, as part of the annual customer notification and information procedures, the NSP Companies state that they will

[77] Accounting procedures that have satisfied this burden have provided internal procedures, processes, and/or journal entries intended to prevent costs recovered in current rates from being included in future rates. For example, entities have provided detailed narratives and illustrations showing modifications to the accounting system to identify and segregate work orders associated with projects that include CWIP in rate base. These accounting procedures also explain the manner in which the costs of a work order will be traced to specific FERC accounts based on the appropriate accounting treatment. Other entities have provided accounting procedures showing and explaining specific accounting journal entries that ensure that no improper capitalization occurs. There may also be other accounting procedures and methodologies that satisfactorily achieve the objectives described above. *See, e.g.*, The United Illuminating Company, Docket No. ER07-653-000, Ex. Nos. UI-13, UI-14 and UI-15 (filed Mar. 23, 2007); Boston Edison Company, Docket No. ER05-69-000, Ex. Nos. BE-2 (at 4-5) and BE-6 (filed Oct. 25, 2004); American Transmission Company LLC, Docket No. ER04-108-000, Ex. Nos. ATC-9 and ATC-10 (filed Oct. 30, 2003).

[78] Transmittal Letter at 33.

develop and post on OASIS work papers that show the cost information and in-service date assumptions regarding the transmission projects and CWIP amounts to be included in their estimates for each year.[79]

68. The Commission has previously accepted a utility's proposal that the FERC Form No. 730 report would satisfy the Commission's requirement for an annual filing for CWIP recovery through a rate formula.[80] Accordingly, we will accept the NSP Companies' proposal to use their FERC Form No. 730 report to satisfy the filing requirements for CWIP recovery through their rate formula, subject to one condition. In their annual FERC Form No. 730 report, the NSP Companies should report the date upon which the Minnesota Commission issued a Certificate of Need for each project. We will also accept the NSP Companies' proposal to develop and post on OASIS work papers that show the cost information and in-service date assumptions regarding the transmission projects and CWIP amounts to be included in their estimates for each year.

C. Rate Formula

69. The Commission will conditionally accept for filing the NSP Companies' proposal to use projected test year cost inputs with a true-up mechanism, effective January 1, 2008. Our analysis indicates that the NSP Companies' proposal to switch to forward-looking estimated transmission costs with a true-up mechanism is just and reasonable. The use of projected costs is consistent with the Attachment O rate formulas that we have approved for Michigan Electric and International Transmission.

70. The NSP Companies will conduct the same kinds of customer meetings to share information regarding the rate inputs as the Commission approved for Michigan Electric and International Transmission, and, with one exception, the NSP Companies have adopted substantially the same tariff provisions approved by the Commission for Michigan Electric regarding sharing information. That exception involves the date by which the estimated revenue requirement for the following calendar year would be provided to customers. The NSP Companies propose to provide customers with such information by October 1 each year, while Michigan Electric and International Transmission provide the information by September 1. Because the customer meeting is held before October 31, we believe that customers should receive such information earlier than October 1 in order to allow sufficient time to review the information before the meeting. Therefore, we will require that the NSP Companies provide the estimated

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[79] *Id.*

[80] *The United Illuminating Co.*, 119 FERC ¶ 61,182, at P 92 (2007).

revenue requirement for the following calendar year by September 1. These information sharing procedures will provide customers sufficient opportunity to monitor whether the NSP Companies are implementing the rate formula correctly.

71. Municipal Intervenors contend that it is not yet clear whether these procedures will provide for a sufficiently detailed information exchange between the NSP Companies and their customers, or for adequate time and procedures for follow-up questioning and informal discovery. The proposed tariff provisions state that the NSP Companies shall make available to customers their projected net revenue requirement and that all inputs shall be provided in sufficient detail to identify the components of such revenue requirement. We expect that the NSP Companies will provide sufficient information to demonstrate that they are implementing their formula correctly in the information distributed by each September 1, and that they will supplement that information if necessary upon request of customers. Municipal Intervenors also argue that in the event that errors are made in the NSP Companies' implementation of formula inputs, there appears to be no mechanism for ensuring that corrections can be made. If errors are detected in the course of information exchange between the NSP Companies and their customers, customers may seek to resolve these matters informally with the NSP Companies or they may seek to have the Commission resolve the matter by filing a formal complaint with the Commission.

72. We reject MMPA's assertion here that the Commission should initiate an investigation of the baseline ROE of the NSP Companies. The NSP Companies do not propose to change the Commission-authorized ROE applicable for all Midwest ISO transmission owners under the Attachment O rate formula. As such, as the proponent of a change in an unchanged component of rates, MMPA bears the burden under section 206 of the FPA to show that the existing ROE is unjust and unreasonable and that a different ROE and capital structure are just and reasonable.[81] The Commission has

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[81] *See Boston Edison Company*, 65 FERC ¶ 61,311, at 62,425-27 (1993), *reh'g denied*, 66 FERC ¶ 61,337 (1994) (In addressing a proposal to increase the nuclear decommissioning cost recovery component of a rate formula without changing the ROE component, the Commission reviewed court decisions on the subject and determined that only if the increase that the utility proposes sufficiently increases its earnings so that the rate of return rises above what the Commission had previously allowed may the Commission change the return under section 205). In addressing International Transmission's proposal to revise its Attachment O rate formula to use projected test-period data instead of historic test-period data, the Commission found the justness and reasonableness of the unchanged ROE component of the rate formula to be beyond the scope of that section 205 proceeding. *International Transmission*, 116 FERC ¶ 61,036 at (continued...)

discretion in deciding whether to initiate investigations pursuant to section 206 of the FPA and whether to set the issue for a formal hearing. While factors such as CWIP and abandoned plant recovery and formula true-up mechanisms can decrease a company's business risk, a number of factors have a bearing on a company's overall business risk. We find that MMPA's assertions that the currently authorized ROE is no longer just and reasonable are too general and unsupported to warrant initiation of a section 206 investigation.

73. We will dismiss MMPA's allegations of price squeeze.[82] As these allegations focus on the ROE, they are outside the scope of this proceeding.[83] Moreover, MMPA has failed to include the minimum information required by the Commission's regulations to have price squeeze considered in a section 205 rate proceeding.[84]

P 35. That holding applies equally to the instant proceeding, where the NSP Companies propose to revise their rate formula not only to use projected test-period data but also to provide for 100 percent CWIP Recovery. Like the switch to use of projected test-period data, 100 percent CWIP Recovery does not change the amount that the utility ultimately recovers for service, just the timing of such recovery. *See, e.g., International Transmission*, 116 FERC ¶ 61,036 at P 19; *Michigan Electric*, 117 FERC ¶ 61,314 at P 17. With respect to 100 percent Abandoned Plant Recovery, no rate change is being sought as this time; the NSP Companies propose to fix the value of this line item at zero and will only change this value through a new section 205 filing.

[82] While MMPA also argues that the difference between the ROE allowance reflected in bundled retail rates and the ROE reflected in wholesale transmission rates violates the comparability principles under the Commission open access rules, we view this argument as essentially an allegation of regulatory price squeeze.

[83] The Commission's regulations regarding proposals to include CWIP in rate base do require that a utility address the potential for *CWIP-related* price squeeze if the requested percentage of wholesale CWIP recovery sought exceeds that permitted by the relevant state or local authority to support the currently competing retail rates. As relevant to MMPA and its members, the NSP Companies indicate in their application that the Minnesota Commission has approved NSP Minnesota's proposal for inclusion of 100 percent CWIP in rate base in retail rates, and, therefore, no further analysis of the potential for price squeeze is required.

[84] 18 C.F.R. § 2.17(a) (2007).

D. Central Minnesota Municipal Power Agency Motion and Request for Declaratory Order for Incentives

74. The Commission rejects CMMPA's request for a declaratory order without prejudice. If a party other than the applicant wishes to request incentive rate treatment, it must submit such a request in a separate petition for a declaratory order or make a filing under section 205 of the FPA in order to give both the Commission and the public proper notice of the proposed incentive filing and allow for a meaningful comment period.[85]

The Commission orders:

(A) The NSP Companies' requested incentives and proposed rate formula modifications are hereby accepted for filing to become effective January 1, 2008, as discussed in the body of this order.

(B) The NSP Companies are hereby ordered to make a compliance filing, to be submitted within 30 days of this order, with proposed journal entries reflecting: (1) all the accounting entries related to the projects; (2) narrative explanations describing the basis for the accounting entries; and (3) a description of procedures and controls that the NSP Companies will implement to prevent improper capitalization, as discussed above.

(C) CMMPA/MMTG's request for a declaratory order is hereby rejected without prejudice, as discussed above.

By the Commission. Commissioner Kelly concurring with a separate statement attached.

(S E A L)

Kimberly D. Bose,
Secretary.

[85] *Louisville Gas and Electric Company*, 62 FERC ¶ 61,016, at 61,151-52 (1993); *American Electric Power Service Corporation*, 90 FERC ¶ 81,040, at 61,193 (2000).

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Xcel Energy Services, Inc. Docket No. ER07-1415-000

(Issued December 21, 2007)

KELLY, Commissioner, *concurring*:

This order addresses a request for transmission rate incentives submitted by Xcel Energy Services Inc., on behalf of the Northern States Power Companies (NSP Companies). In accordance with criteria I have specified in previous statements,[1] I conclude that the NSP Companies have demonstrated that the projects addressed in this proceeding warrant incentive rate treatment. The NSP Companies have requested two types of incentive rate treatments for 6 projects: 100 percent of prudently incurred Construction Work in Progress (CWIP) in rate base and recovery of 100 percent of prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond their control. The NSP Companies have also demonstrated that the requested CWIP and abandonment costs incentives are warranted.

Four of the six projects represent the initial group of transmission projects planned as part of the CapX 2020 project, which involves eleven Midwest utilities.[2] I conclude that these projects merit incentive rate treatment for several reasons. First, these projects represent backbone transmission infrastructure and were the product of a coordinated planning process among a large group of investor-owned utilities and cooperative and municipal power agencies. Second, the CapX 2020 projects are intended to provide for regional transmission needs going forward 15 years or more. Furthermore, I have made this determination on the basis of the size of the investment ($800-$940 million for the NSP Companies) and the lead times involved. I conclude that the specific incentives sought—100 percent CWIP and abandonment costs incentives—are appropriate because they will mitigate the primary risks of the projects, i.e., the long/uncertain lead times, effects of capital expenditures on cash flows and creditworthiness, and the possibility that they might not be completed.

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[1] See *American Electric Power Service Corporation*, 118 FERC ¶61,041 (2007).

[2] NSP Companies are joined in the CapX 2020 efforts by ten other utilities: Great River Energy, Minnesota Power, Missouri River Energy Services and Otter Tail Power Company, Dairyland Power Cooperative, the Central Minnesota Municipal Power Agency, Minnkota Power Cooperative, Rochester Public Utilities, Southern Minnesota Municipal Power Agency, and Wisconsin Public Power, Inc.

With regard to the Buffalo Ridge Incremental Generation Outlet (BRIGO) and Chisago-Apple projects, I also find that these warrant incentive rate treatment. The BRIGO project not only provides delivery capability for future wind generation, it enhances operations of CapX 2020 projects, and increases the reliability of the transmission network. Moreover, the BRIGO project resulted from a multi-utility study, which determined that it "provided the greatest increase in wind generation outlet capacity at the lowest cost."[3] I base my decision concerning the Chisago-Apple project on the fact that it is multi-state, multi-jurisdictional[4] and a jointly-owned project. I also note that the NSP Companies and its partner have faced opposition to a transmission solution in the Chisago-Apple area for 12 years.[5] The requested CWIP and abandoned plant incentives are appropriate for these projects given the risks these projects face: long lead time and the need to obtain regulatory approvals from a disparate set of authorities, some of which NSP Companies have not dealt with in prior projects.

For these reasons, I respectfully concur with this order.

Suedeen G. Kelly

[3] See Exhibit XES-8 at 12:2-4.

[4] NSP Companies note that approval for the project must also be sought from the U.S. Army Corp of Engineers and National Park Service in addition to Minnesota and Wisconsin authorities.

[5] See Exhibit XES-8 at 5: 15-20.

APPENDIX C – COST ALLOCATION ACROSS MULTIPLE UTILITIES

Before discussing cost allocation, it is necessary to consider funding. While cost allocation is concerned with who ultimately pays the project owner for its investment in transmission infrastructure, the funding discussion determines who spends the capital to get the iron in the ground and the wires strung. For most of the past 100 years of transmission building in the U.S., the incumbent or local utility designed and built transmission facilities and then through regulatory proceedings, placed those investments in rate base for recovery from its various customer classes. The exception is where public power or other non-regulated entities built new transmission to be paid for through its rates to various end users. Now, due to a number of outside influences, utilities must consider regional transmission expansion projects and partnership arrangements. Regional transmission solutions may cross several state lines, include numerous incumbent utilities, include non-traditional entities, and may involve multiple state regulatory bodies.

One Xcel Energy operating company, Northern States Power, is involved with such a regional project. The CAPX 20/20 project involves numerous 230 kV and 345 kV transmission lines across South Dakota and Minnesota. Several companies are working together and that includes both state jurisdictional and non-jurisdictional entities. Those entities operate under the organized RTO, namely MISO, with established cost allocation practices but the decisions on ownership and funding are proving to be difficult. Even an organized regional market does not guarantee ease in regional project funding.

Absent an organized market in the West, cost allocation is limited to the individual company building a project. Jointly owned projects face a complex process of determining ownership models and percentages and then face regulatory hurdles in justifying those numbers for cost recovery to their state regulatory bodies or membership, depending on their entity structure.

In looking at possible funding and cost allocation possibilities for regional transmission expansion, it is worth considering how cost those functions are handled in a few organized markets. As described previously, Xcel Energy operates transmission systems in both the MISO and SPP regions. Both have similar cost allocation models developed almost entirely by the state regulator groups in these areas (see discussion of SPP RSC and MISO OMS below). Both areas recognize the regional nature of higher voltage transmission and seek to allocate costs on a more regional basis than stand-alone entities. With the growth of renewable energy, disbursed third-party owned generation and the FERC's stated goal of a competitive transmission model, transmission systems must now reach beyond single system owners and cross political boundaries. In doing so, projects in one area can actually provide benefits to entities many miles away through congestion relief, changed flows, and new market opportunities. While the West is recognizing this in the transmission planning process, the organized markets in the East have taken it a step further and have begun to assign or allocate costs of projects to the actual beneficiaries using various modeling techniques.

Transmission pricing across multiple utilities is at the wholesale, not retail, level. Thus, for example, Regional Transmission Organizations (RTOs) have no direct impact on retail pricing. Once costs are allocated to a utility through its Annual Transmission Revenue Requirement (ATRR) either by a Postage Stamp or Benefit Model, its wholesale customers and Merchant function must pay a rate that allows recovery of that ATRR. The utility's Merchant buys transmission (based on the ATRR) for serving its native load, and the utility seeks recovery at each state with jurisdiction for recovery of ATRR costs in its requested retail rates.

Under a Postage Stamp model, the costs of any new transmission project in an organized area (such as an RTO) are shared among all zones (roughly following Balancing Authority lines) on an equitable basis such as load ratio share. Postage Stamp allocation can spread costs across numerous states and jurisdictions, but is generally limited to higher voltage projects such as 345 kV and higher. Projects of that voltage are thought to provide benefits well beyond the boundaries of single Balancing Authorities, and lower voltage projects are generally thought to only benefit local systems.

In contrast, a Benefit Model allocates costs only to zones receiving benefits. Both the Southwestern Power Pool (SPP) and the Midwest Independent System Operator (MISO) use a percentage Postage Stamp across the region and a percentage of a Benefit Model. For the Benefit Model percentage calculation, MISO uses Line Outage Distribution Factor (LODF) and SPP uses MW-mile (MW-MI) for the remainder. Both RTOs allocate portions of costs of some new projects to everyone (postage stamp) and additional portions to those who are closest to (or benefit from) the project. LODF is the percentage of flow from Line A that is transferred to Line B as a result of the loss of Line A; it looks at where flows are impacted by a new project and then weights allocation to zones based on the result on a percentage basis of flows. MW-MI allocates costs based on megawatts, and is done now for reliability projects only.

The major difference is that while LODF looks at percentage of flows while the MW-Mile model looks simply at MW flows. The megawatt-mile technique is a distance based impact method of assessing transmission use and topology recognizing that power will, to some extent, flow over all available paths from the generating source to the load. The network models used in the MW-mile calculations are derived from loadflow models of the Transmission System assembled annually by SPP. The incremental MW-mile is determined by building the base case with all Base Plan Upgrades in service. A MW-mile calculation is performed by measuring the flows on each line multiplied by the distance. The net change of the MW-mile impacts is used for this calculation. Then a benefit determination calculation is made with each new transmission upgrade removed individually. The reduction in MW-mile impact due to each new transmission upgrade is the measure of its zonal benefit.

The advantage of the Postage Stamp Model is that all transmission entities pay based on a simple formula, thus it eliminates debate, is easily forecasted, and allocates costs easily. The advantage of the Benefit Model is that only those who benefit pay, and thus it is more fairly allocated, there is less chance for conflict between the paying entities, and it may be more politically palatable to regulatory bodies.

The following represents how Xcel Energy utilities in MISO and SPP regions are allocated wholesale transmission costs:

MISO RECB I Regionally beneficial projects	■ 345 kV and above: allocated among all MISO pricing zones based on 20% MISO-wide postage stamp / 80% based on LODF ■ 100 kV and above: All pricing zones 100% based on LODF ■ <100 kV: 100% to home pricing zone ■ GI network upgrades: 50% to customer and 50% BRPs rules
MISO RECB II Economic projects	■ Inclusion metric to identify BRPs is 30% LMP / 70% production cost reductions. Benefit/cost thresholds are 1.2 for projects one year out, increase linearly to 3.0 for projects 10 years out ■ Limited to 345 kV or greater initially ■ 20% is allocated through a MISO-wide postage stamp charge ■ 80% allocated through sub-regional postage stamp charges, in proportion to benefits identified for inclusion in each subregion
SPP	**Reliability Projects (No voltage requirements)** ■ 67% zonal (determined by MW-MI) ■ 33% postage stamp

In contrast to "Reliability Projects" (shown in the above chart), Economic Projects are not driven by reliability needs as they are built to access lower cost resources or to provide an outlet for resources. For Economic Projects, the SPP Regional State Committee (RSC) first approved a 100% Postage Stamp rate for 345 kV and higher transmission lines. However, it is now looking at a modified Postage Stamp/Benefits Model, in which a Postage Stamp rate is charged to all zones meeting a certain threshold of financial benefit in the footprint for a specific project; thus, if there are no benefits to a zone, there is no allocation to that zone for that project but then that zone will receive approval for lower voltage projects to "balance" the portfolio and all zones will still see a fair and even Postage Stamp distribution of costs. The development of such cost allocation structure is in process now, and is expected to be filed with FERC by the end of 2008.

On the issue of rate pancaking, WestConnect has developed a regional pricing two-year pilot experiment to eliminate rate pancaking for hourly non-firm transactions, for which it is seeking FERC approval. If approved, the experiment is to begin in early 2009. The pilot program eliminates transmission rate pancaking for limited transactions, and continues to pancake ancillary services and losses. Participants retain their posted OATT rates, and revenue is distributed pro rata based on posted rates. Start-up and implementation costs are borne by Transmission Customers (thru OATI), and the program can be implemented through the WesTTrans platform.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Interconnection Queuing Practices	)	**Docket No. AD08-2-000**

COMMENTS OF XCEL ENERGY SERVICES INC.
IN TECHNICAL CONFERENCE

Pursuant to Rule 212 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.212 (2007), and the notice issued by the Commission in the above-captioned docket on December 17, 2007, "Notice Inviting Comments," Xcel Energy Services Inc. ("XES"), on behalf of the Xcel Energy Operating Companies (collectively "Xcel Energy"),[1] hereby submits these Comments in the above-captioned proceeding.[2]

I. MOTION FOR LEAVE TO FILE COMMENTS OUT OF TIME

XES respectfully requests that the Commission exercise its discretion and accept these comments out of time. XES represents that it has a substantial interest in the above-captioned proceeding. XES believes that its Comments in this proceeding will be of assistance and contribute to the Commission's analysis of generation interconnection

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[1] The four Xcel Energy Operating Companies are Northern States Power Company, a Minnesota corporation ("NSP"); Northern States Power Company, a Wisconsin corporation ("NSPW") (jointly the "NSP Companies"); Southwestern Public Service Company ("SPS"); and Public Service Company of Colorado ("PSCo"). XES is the service company for the Xcel Energy Inc. public utility holding company system and, *inter alia*, represents the interests of the Xcel Energy Operating Companies in proceedings before the Commission.

[2] In addition to these comments, the NSP Companies joined the written comments submitted by the Midwest ISO Transmission Owners on January 10, 2008.

queuing issues that have arisen since the issuance of Order No. 2003.[3] Because of deadlines in other Commission and state regulatory proceedings, Xcel Energy was unable to file these comments by the January 10, 2007 deadline. However, these comments are being filed only three business days out of time. Moreover, accepting these Comments out of time, particularly in light of the voluntary nature of this technical conference docket, will not disrupt this proceeding, cause undue delay, or unfairly burden other participants.

II. COMMUNICATIONS AND NOTICES

Xcel Energy requests that the following persons be placed on the service list in this proceeding:

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3 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160; *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004); *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005); *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007). See also *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180; *order on reh'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005); *order granting clarification*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006); *appeal pending sub nom. Consol. Edison Co. of N.Y., Inc. v. FERC*, Nos. 06-1275, *et al.* (D.C. Cir. filed July 14, 2006 and later); *Interconnection for Wind Energy*, Order No. 661, FERC Stats. & Regs. ¶ 31,186 (2005), *order on reh'g*, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 (2005).

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III. INTRODUCTION

In 2003, the Commission issued Order No. 2003 to standardize the agreements and procedures related to the interconnection of large generating facilities (20 MW or larger). In that order, the Commission found that "[a] standard set of procedures as part of the OATT for all jurisdictional transmission facilities will minimize opportunities for undue discrimination and expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable."[4] As the Commission has noted, key to appropriately balancing these goals was the adoption of a set of comprehensive queue management procedures.[5]

From Xcel Energy's perspective, Order No. 2003 has provided substantial benefits in terms of standardization of the process and contractual arrangements for new generation interconnections. Since Order No. 2003 was issued, the Xcel Energy Operating Companies have executed more than 70 Large Generation Interconnection Agreements ("LGIAs") using the standard form adopted in Order No. 2003, and more than 80 additional interconnection requests are in various stages of completing the Large Generation Interconnection Process ("LGIP"). The vast majority of the executed LGIAs and pending requests relate to non-affiliated generation, and the Xcel Energy Operating

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4 Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 11.

5 *Second Notice of Technical Conference* (Docket Nos. AD08-2-000 *et al.*) (November 30, 2007).

Companies have invested hundreds of millions of dollars in new transmission infrastructure to accommodate the interconnection and provide transmission capacity to deliver that generation to our load centers. Without the standardized process and LGIA, it is unlikely so many generation interconnection requests could have been processed and interconnection agreements executed.

Recently, however, the Commission has acknowledged that a number of queue-related issues have arisen in the industry since the issuance of Order No. 2003 because of market developments not anticipated in the Order No. 2003 rulemaking. Some regions are experiencing various challenges in attempting to manage their interconnection request queues due to surges in the volume of proposed generation development. The Commission also has recognized that an unprecedented demand in some regions for new types of generation, principally renewable generation, has placed further stress on the current queue management approach because such generation technologies can, for example, be brought online more quickly than traditional fossil fuel central station generation.

In response to these concerns, the Commission held the Technical Conference to seek information regarding any queue issues that may have arisen since the issuance of Order No. 2003 and to examine solutions that may have been developed or proposed to deal with those queue issues. Following the Technical Conference, the Commission issued a notice inviting comments on interconnection queuing practices and potential solutions. The following comments are hereby submitted accordingly.

IV. COMMENTS

A. General Comments

1. Xcel Energy Provides a Unique Perspective

Xcel Energy applauds the Commission's proactive efforts in identifying and establishing a forum to consider and resolve the escalating interconnection queue congestion concerns. However, Xcel Energy urges the Commission to avoid resolving the various queue management concerns with a single solution, such as a rulemaking.

Xcel Energy is one of the few public utilities in the United States that has major electric operations in both the Eastern and Western Interconnections and in three distinct markets: the NSP Companies operate in the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") regional transmission organization ("RTO") region; SPS operates in the Southwest Power Pool ("SPP") RTO region; and PSCo operates as a vertically-integrated utility in the Western Interconnection. As such, generation interconnection requests for the NSP Companies integrated system ("NSP System") are administered by the Midwest ISO, generation interconnection requests to the SPS system are administered by the SPP, and generation interconnection requests to the PSCo system are administered by PSCo.

2. The Commission Should Allow Regional Differences

Based on our experiences in these different markets, Xcel Energy recognizes that, to a certain extent, some of the interconnection queuing issues facing the industry are similar across the regions. However, we believe that while many regions may experience similar queuing problems, the reasons for these problems tend to vary based on the region. Thus, solutions are more appropriately developed at the regional level. Indeed, some regions - the Midwest ISO and SPP, for example - are already working with stakeholders to develop solutions to improve the interconnection queuing process that would solve the specific issues faced in the region.

To facilitate the development of regional solutions, Xcel Energy strongly recommends that the Commission be open to regional differences in interconnection queue managements, and not mandate a "one size fits all" solution by rulemaking. For example, the Commission could flexibly interpret the "consistent with or superior to" requirement in Order No. 890 and Order No. 2003 to allow RTOs and transmission providers to suggest solutions for managing the interconnection queue. The Commission should allow transmission service providers to propose alternative queuing management processes that continue to prevent undue preference for transmission owner affiliates, yet would allow viable interconnection requests to be processed prior to more speculative projects. Particularly in the context of an independent RTO, the Commission could allow for regional, RTO-specific solutions.[6]

In the following comments, Xcel Energy discusses various queue-related issues we have identified in each of the regions in which an Xcel Energy Operating Company operates. We also propose certain solutions that we believe could be more fully developed and tailored to meet the needs of the specific region. Here, we highlight several interconnection queue issues that are shared by each of the regions in which we operate (though we propose that each of these concerns be addressed at the regional level). We suggest these solutions because it is increasingly evident that Order No. 2003, as written, is now becoming an impediment to the timely connection of additional new

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[6] Allowing such "regional differences" would be analogous to allowing Regional Entities responsible for North American Electric Reliability Corporation ("NERC") mandatory electric reliability standard to adopt modified standards that meet the unique needs of the region.

generation and the construction of the new transmission infrastructure needed to serve the needs of both generators and consumers.

3. Common Issues Across Regions

First, as we discuss more fully below, each region suffers from an oversubscribed queue that is replete with many projects that will almost certainly never be developed. Xcel Energy believes that one of the root causes is that the process to enter a transmission provider's interconnection queue is too easy and inexpensive – it requires only a completed Interconnection Request application that is accompanied by a refundable $10,000 deposit. The requirements to obtain and retain a place in the queue need to be increased.[7]

In addition, another significant contributing cause to queue congestion is the method of assigning queue positions established in Order No. 2003. Under the interconnection procedures adopted in Order No. 2003, a generator that submits an Interconnection Request is assigned a position in the queue on a "first-in, first served" basis. Thus, priority is based solely on when the interconnection request application was completed, regardless of when the generator is proposed to go into service, the capacity

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[7] The NSP Companies and PSCo also operate retail natural gas local distribution company ("LDC") systems, and must procure incremental gas transmission capacity and load serving interconnections through "open season" processes operated by interstate natural gas pipelines regulated by the Commission. In those processes, a requestor typically must agree to long-term contractual and financial obligations to obtain and retain a spot in the queue. To our knowledge, pipelines apply similar requirements to producers, gathering companies or processing plants that seek to interconnect to a pipeline in supply regions, the functional analogy to interconnection of a new generator. Although pipeline open season processes can be oversubscribed, in our experience the oversubscription levels are more manageable. In addition, we are not aware of Commission rules expressly mandating how pipelines are to administer their open seasons; they are simply subject to non-discrimination and transparency requirements. Xcel Energy believes the Commission should consider the example of the pipeline industry in evaluating queue management proposals proposed by transmission providers.

factor or the viability of the interconnection request. While this process was intended to assign priority on a non-discriminatory basis, Xcel Energy believes that the "first-come, first-out" process, especially when combined with Order No. 2003's liberal suspension policy, has contributed to the queue congestion. Transmission providers should be allowed to suggest alternative prioritization methods, as long as the process is administered in a transparent and non-discriminatory manner.

Finally, Xcel Energy believes that the suspension policy set forth in Section 5.16 of the LGIA is too liberal and must be revised. Under Order No. 2003's interconnection procedures, a generator that submits an interconnection request and executes an interconnection agreement may then suspend that request at relatively little cost (financial or otherwise) for up to three years simply by providing notice. The Xcel Energy Operating Companies have received several such suspension notices for projects that have completed the LGIP through execution of the LGIA. This suspension policy not only complicates a transmission provider's evaluation processes, but also creates uncertainty and risk for projects that entered the interconnection queue after the suspended projects. The transmission provider must hold a spot in the queue, with no knowledge whether the project will be unsuspended and constructed (along with any associated network upgrades), or whether the suspension period will simply expire after three years. The suspension policy thus detrimentally affects the ability of transmission providers and lower queued projects -- even viable ones -- which does not serve the public interest.

While each region should be allowed to develop its own solutions, we suggest the following conceptual ideas. First, the requirements to enter the interconnection queue should be made more stringent. This could be achieved by raising the application fee significantly, and making the deposit non-refundable, to deter the submission of more speculative interconnection requests. In addition, or possibly in the alternative,[8] Xcel Energy strongly recommends that each region establish meaningful milestones that developers would be required to stay in the queue and proceed through the respective interconnection study phases. These milestones should be vigorous demonstrations of the viability or the state of active development of a generation project and should give projects with a binding load serving commitment a higher priority. Moreover, Xcel Energy believes that the current suspension procedures in LGIA Section 5.16 should be either eliminated or made significantly more stringent.

B. System Specific Comments

1. NSP Companies and the Midwest ISO

Xcel Energy agrees with the Midwest ISO's assessment at the Technical Conference that its Order No. 2003 compliant LGIP/LGIA initially worked well to facilitate study and interconnection-related requests that were proposed for the Midwest ISO footprint. However, while the process continues to work as designed, the design no longer works given the current situation in the Midwest ISO.

As discussed at the Technical Conference, the number of interconnection requests in the Midwest ISO has "exploded" in recent years. The Midwest ISO received 191 requests for generation interconnection in 2007, a 59% increase over the level of requests in 2006 and more than double the level of requests received in each of the years from

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[8] While Xcel Energy strongly encourages that the fees be raised to a more meaningful level, we also recognize that not all developers would be able to afford significantly higher fees. However, we believe solutions would be available and will be developed through stakeholder processes.

2002 – 2005.[9] The NSP Companies are particularly affected since there are more pending requests to interconnect to the NSP System -- 52 current requests involving a total of approximately 6,900 MW -- than the transmission system of any other Midwest ISO member utility. These requests are primarily for wind generation projects that are (or will be) located long distances away from loads and that have entered the queue process in part because of state-legislated renewable energy standards. As a result of this dramatic increase in interconnection requests, the Midwest ISO now has a backlog of pending requests in its queue that it estimates will not be cleared until 2050 if it continues to use the Order No. 2003 interconnection procedures.[10]

The most significant problems with the current Midwest ISO queue management process are: (1) the "first in - first out" process mandated by Order No. 2003, which makes queue positions valuable, whether or not the proposed generation projects are commercially viable or capable of moving forward in a timely manner; (2) the liberal suspension policy set forth in Section 5.16 of the LGIA, which allows speculative projects to execute an LGIA, immediately suspend the interconnection agreement, but retain valuable queue positions for up to three years at a minimal cost, thereby complicating evaluation of lower-queued projects; (3) the "straw that breaks the camel's back" process of assigning transmission network upgrade costs to the individual generation project(s) that push the capacity of a specific transmission facility over its

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[9] See *Prepared Remarks of Clair J. Moeller, Vice President of Transmission Asset Management Midwest Independent Transmission System Operator, Inc.*, (Docket No. AD08-2-000) (December 11, 2007).

[10] On January 14, 2007, Xcel Energy received notification from the Midwest ISO that it does not expect to begin the studies for interconnection requests *already in the queue* and assigned to the "Group 19" group interconnection study until 2018, eleven years after submission of the request.

rating, which encourages developers to enter the queue multiple times and/or then withdraw specific requests to either take advantage of transmission capacity created by earlier queued projects or to shift the cost of network upgrades onto another generator, exacerbating queue congestion and requiring multiple iterations of interconnection studies; (4) the current methodology by which the Midwest ISO studies projects in groups, which leads to seemingly endless iterations of study rework because of the high "drop out" rate for projects;[11] and, (5) the current project-by-project (or group by group) evaluation approach, which makes it difficult to create an optimal set of transmission expansion plans, even in the context of the annual Midwest ISO Transmission Expansion Plan ("MTEP") process.

Solving these problems will require several modifications to the existing interconnection procedures and certain other provisions in the Midwest ISO's tariff. As noted above, efforts are already underway in the Midwest ISO to work with stakeholders to improve the interconnection queuing process. Xcel Energy supports those efforts and recommends the following conceptual changes.

First, the Midwest ISO should be allowed to move from a "first in – first out" to a "first finished – first out" process that contains a series of milestones a project would be required to meet in order to proceed through the interconnection process and retain its queue position. This change would enable projects with an earlier scheduled completion date to jump ahead of projects scheduled further into the future or that may be more

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[11] Xcel Energy strongly supports the use of "group studies" that seek to "cluster" similarly located interconnection requests, but the group study process is frustrated when projects are suspended or multiple interconnection requests are submitted. The initial results of the group study can cause projects to suspend or withdraw -- *e.g.*, in order to avoid an allocation of network upgrade costs -- resulting in the need for restudies, often in multiple iterations.

speculative or less viable. Projects unable to complete their milestones would be dropped from the queue entirely, thus ridding the queue of "phantom" projects.

Second, the Midwest ISO should be allowed to reform the current suspension rules in Section 5.16 of the LGIA to require suspended projects to "step out of line" if they issue a notice of suspension, and require restudy of the suspended projects if and when they end their suspension and re-enter the queue. This would remove much of the value of queue positions that results from the current suspension rules, and would also reduce the current incentives to file an interconnection request, complete the LGIP and LGIA execution process, and then immediately suspend the project.

Third, Xcel Energy recommends that the Midwest ISO be allowed to require a non-refundable deposit from new queue entrants to correct the situation today where generators can drop out of the queue and have their full deposits refunded if it is before any study costs have been incurred. Alternatively, Xcel Energy recommends that MISO be allowed to significantly increase the $10,000 entry fee; the actual increase should be established through the MISO stakeholder process.

Fourth, Xcel Energy believes it would be prudent for the Midwest ISO to identify geographic areas where there are likely to be multiple projects developed during the same time frame. The Midwest ISO should then develop both short-term and long-term transmission expansion plans to accommodate the expected development, particularly for location-constrained renewable resources being proposed to meet state-mandated renewable energy standards. For example, the Midwest ISO could conduct an "open season" process that would seek interconnection requests from a specific geographic area proposed to be interconnected over a period of time, and then develop a long range transmission plan -- via the MTEP process -- to construct transmission to meet the collective need, rather than piecemeal incremental plans to meet the requirements of individual requests (or small groups of requests).

Finally, Xcel Energy recommends that the Midwest ISO be allowed to develop cost allocation procedures to allocate the costs of identified network upgrades equitably among all new generation projects whose interconnection is enabled by such upgrades, rather than apply the "straw that breaks the camel's back" methodology that can cause individual interconnection requests to be allocated millions of dollars of network upgrade costs while the next project in the queue effectively receives a "free ride" because capacity is now available. Alternatively, or perhaps in coordination with this change, the Midwest ISO should consider pricing methodologies that would allocate the cost of network upgrades directly to the loads to be served by the incremental generation. Since all interconnection and network upgrade costs are ultimately borne by end users, and the load being served may be distant from the location (and transmission system) where the generator will be located (particularly for renewable wind generation), a load based cost allocation methodology would allow the loads that benefit from the new generation to directly pay the cost, rather than have the interconnecting generator pay the costs and then seek to collect the costs in the price of the generation sold to the load.

Xcel Energy recognizes that many challenges and hurdles would need to be overcome in order to achieve these proposed solutions. However, Xcel Energy believes these obstacles should be resolved through an open stakeholder process and region-specific revisions to the Midwest ISO tariff rather than through a Commission rulemaking procedure.

2. SPS and SPP

As in the Midwest ISO, there is a tremendous demand in the SPP region for the interconnection of new generation, principally renewable generation.[12] As with the NSP System, a large number of those requests seek interconnection to the SPS transmission system. As of the end of December 2007, there were 32 pending interconnection requests seeking to interconnect approximately 9,200 MW of new generation, most of which is wind generation, to the SPS transmission system. The interconnection requests far exceed the peak load on the SPS system (approximately 5,100 MW). This demand has led to the current interconnection queue management system used by the SPP being stressed far beyond what was contemplated in Order No. 2003. Based on recent experience with the SPP interconnection queue process, Xcel Energy has identified the following issues and proposes several possible solutions.

First, under the SPP interconnection queue management process (as required by Order No. 2003), all generation interconnection requests are prioritized on a "first-in, first-out" basis. The priority is based solely on when the interconnection request application is completed, and is regardless of whether the requestor has a signed power purchase agreement ("PPA") and firm financial arrangements in place to construct the generator, or is merely speculative. Currently, there are a significant number of

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12 SPP states that from 2003 through 2005, it received 24 interconnection requests each year. In 2006, that number jumped to 49. In 2007, SPP received 53 requests. Of the 76 active requests in the SPP queue in December 2007, 67 were for wind generation projects. See *December 11, 2007 FERC Technical Conference Prepared Statement of Charles Hendrix Senior Engineer, Southwest Power Pool* (Docket No. AD08-2-000) (December 11, 2007).

renewable generation requests in the SPP queue that appear to be speculative.[13] As a result of the current interconnection queue process, if SPS or an IPP with a signed PPA for firm capacity as a network resource were to submit a generation interconnection request, the request could not be timely processed in order to meet the resource needs of SPS's native load customers. Instead, SPP would be studying the requests associated with projects that likely will never be constructed.

One possible solution would be for SPP to study base load resource projects with a high capacity factor potential ahead of low capacity factor projects. Those high-capacity factor projects will provide firm load serving capability to end-use customers as opposed to low capacity resources that will provide energy cost-savings benefits but minimal firm capacity. Alternatively, SPP could adopt a "first-finished, first-out" as proposed above, where generators who complete designated milestones -- e.g., PPAs and financing in place -- would continue through the queue while those who do not are removed from the queue.

Second, generation interconnection requests in SPP increasingly include multiple scenarios to study, which result in different cost allocations for the customers in the queue. For example, if wind interconnection customer A proceeds with its interconnection, then interconnection customer B will have certain facilities available as will customer C. But, if wind interconnection customer A chooses to not interconnect or to suspend its project, then customer B's interconnection facilities and costs will change, as will customer C's. These changes are due to the electrical changes required on the

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13 An example of a "speculative" request is one that is patently inconsistent with the network it proposes to connect with – *e.g.*, a 1,500 MW wind generation plant that seeks to interconnect with a 69 kV transmission network.

system to accommodate large numbers of interconnections on the transmission system where there are significant electrical interactions between the requests. Each one of these interconnection requests will thus generate multiple interconnection scenarios as to what happens if that customer proceeds or does not proceed.[14] SPS and SPP have and continue to experience this unpleasant restudy phenomenon. Further, the interconnection customer will find it difficult to agree to the ambiguous cost allocation scenarios: will it be required to fund $1 million in network upgrades or $10 million? This situation also increases the complexity for SPS' and SPP's planning staffs to determine the transmission facilities SPS and other SPP members will need to plan and build.

Third, the tremendous amount of renewable generation being requested for study in the SPP generation interconnection queue poses several technical challenges for SPP. SPP is struggling to physically model such unprecedented amounts. As discussed previously, in early December 2007, there were approximately 6,300 MW of wind resources in the SPP queue for interconnection to the SPS system. Only a month later, that number has increased to approximately 8,500 MW of wind energy based interconnection requests. By comparison, the peak load for the SPS system is approximately 5,100 MW and SPS's export capability is less than 500 MW. Moreover, if a developer wants a specific point of interconnection to be included in the study, but that interconnection point does not yet exist or have the physical capability for interconnection (*e.g.*, a 400 MW wind generator proposing to interconnect to a 69 kV transmission line), it is virtually impossible for SPP to do a feasible engineering study.

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14 The number of possible scenarios is $2^{(n-1)}$ where n is the number of customers that are strongly electrically inter-related or an exponentially increasing matrix of combinations that may have to be addressed in an interconnection agreement.

The party requesting the interconnection request rarely worries about the problem of the technical study of the interconnection. SPP, along with SPS, is now dealing with situations where it is impossible to perform power flow and stability studies of all of the generation in the queue for the SPS service area.

Since generation must serve load, and a utility like SPS must, pursuant to Commission Order No. 697, also comply with North American Electric Reliability Corporation electric reliability standards, it is technically impossible for all (or even a significant portion) of this generation to interconnect to the SPS transmission system without major transmission upgrades to export the generation to loads on neighboring systems (or even regions). There are significant engineering technical issues with preparing the power flow and stability models that can realistically represent the requests in such circumstances. In effect, it is necessary to build or assume the construction of a new transmission 'network' that does not exist today just to study potential interconnections, regardless of where a generator requests to connect. There is limited flexibility in the Order No. 2003 LGIP to accommodate or deal with this problem, and the issue needs to be addressed.

Fifth, there is often a disconnect between the expectations of generation developers in the SPP queue and the reality of the time it may take to get state regulatory approval of necessary transmission lines once a project makes it through the SPP's interconnection queue. State processes for certifying new transmission facilities cannot be completed as quickly as new wind facilities can be constructed and brought on line. If a project is constructed (or even comes out of suspension), there may not be transmission capacity available to deliver the generation to load, and network transmission facilities must be constructed. Such network transmission facilities may require permitting or certification through state or local approval processes. In our experience, for example, a 200 MW wind farm can be constructed within 9 - 12 months. However, even in areas like the SPS system where transmission construction is not typically opposed and transmission construction can occur more quickly than in most regions, the timeline for state certification and construction of the transmission facilities needed to deliver that 200 MW will be at least 24-36 months depending on the amount of transmission construction. So even if the SPP queue process can be expedited, transmission certification and construction time requirements are still a factor and must be recognized.

Sixth, Xcel Energy strongly recommends the adoption of more stringent standards for entry into the SPP interconnection queue. This could be achieved by raising the current $10,000 deposit, which is too low to differentiate between purely speculative and "real" projects, and thus can delay the evaluation (and thus construction) of projects that are needed and are not speculative.

Furthermore, Xcel Energy believes that the suspension policy required by Section 5.16 of the LGIA should be reformed. Currently, the SPS system has approximately 750 MW of suspended wind generation projects, representing nearly $12 million for potential interconnection and network upgrade costs. The current three-year suspension period effectively creates a contingent liability to the Company, since it may be potentially be required to make substantial future investments, but the timing and likelihood of actual investment are unknown. This financial uncertainty creates unnecessary risks to SPS, and also makes it impossible to efficiently plan and budget for transmission construction needed for projects that clearly will achieve commercial operations.

In addition, the suspension policy could potentially create serious operational concerns for systems where there are large numbers of requests to interconnect wind generation. The current wind penetration level on SPS' system is approximately 12%, and if all of the suspended wind projects came out of suspension over the next three years, the total wind generation connected to the SPS system could be almost 30% of peak load, higher than any other electric utility in the country (to our knowledge). The operational effects of penetration of an intermittent (and non-dispatchable) generation resource at this level are currently not well understood or documented. Moreover, when a developer comes out of a suspension period, it expects SPS to accommodate its schedule, despite SPP and SPS having no notice as to exactly when (or even if) the suspension period will end, or if the project will simply fail to unsuspend and be eliminated from the queue three years hence.

This uncertainty is exacerbated because SPP has more wind energy interconnection requests than most other regional organizations (except the Midwest ISO), but SPP does not "cluster" requests to be studied. Indeed, SPP and its members are divided on whether or not "clustering" is a good solution for queue management or a good technical solution for power system studies. Xcel Energy recommends that SPP "cluster" requests if SPP and its stakeholders determine that such an approach would be beneficial.

Finally, the Commission should be aware of a "loophole" between the Order No. 2003 rules and certain state qualifying facility ("QF") processes that needs to be remedied. SPS is seeing increasing attempts by wind generation developers to request interconnection of a QF at distribution voltage, using a state QF "put" contract to bypass the SPP regional interconnection queue process to interconnect on Xcel Energy's distribution system pursuant to state QF rules. In SPP, radial 69 and 115 kV lines can be classified as distribution lines pursuant to the SPP OATT, and thus no studies of the interconnection request will be performed by SPP. However, the generation resulting from the QF "put" interconnection may be in excess of the load on the distribution or radial line, so that power flows back onto the transmission system. The state QF interconnection procedure effectively enables generation facilities that never go through the SPP Order No. 2003 generation interconnection process to interconnect and use the RTO-managed transmission system. This situation is a serious loophole in the FERC and SPP processes that will affect wind rich areas primarily, but could affect all utilities depending on what new distributed energy technologies are developed.

3. PSCo

Xcel Energy believes that, in general, the Order No. 2003 generation interconnection queue management process has worked adequately for the PSCo system to date. In its Order No. 2003 compliance filings, Xcel Energy included a methodology to incorporate state mandates for integrated resource planning ("IRP") into the structure of the LGIP. This Resource Solicitation Process allows a Load Serving Entity ("LSE") to submit a cluster of generators into the queue with a single queue position. Using this methodology, Xcel Energy has been able to interconnect six new IRP generation resources, including three wind farms since the issuance of Order No. 2003.

However, Xcel Energy believes that there are several problems with the LGIP process which compromise the timeliness and fairness of processing interconnection requests and the effective use of Xcel Energy's transmission resources. PSCo, like many other transmission entities around the country, suffers from an oversubscribed queue consisting of many projects that will never be placed in service. Entering the queue is a fairly simple process that only requires a completed Interconnection Request form and a $10,000 refundable deposit. For the PSCo system, of the 43 generation projects that have been submitted to the queue since 2003, only six have signed PPAs and have been, or are currently being, built. In processing these 43 queue submissions, Xcel Energy has completed 77 LGIP studies representing thousands of both in-house and consulting hours of work.

This backlog demonstrates that the Order No. 2003 interconnection queuing process was not designed to work with the large number of requests such as those that have been received over the past two years. Unfortunately, transmission planning resources are not unlimited, and the Order No. 2003 study deadlines are short. As a result, the PSCo transmission planning function has spent much of the last several years planning for the interconnection of generation projects that will never be constructed and placed in service, rather than allocating those limited resources to planning large scale "backbone" facilities that serve regional generation and load needs. Unless this process is changed, serious impediments to both the timely infrastructure expansion needed to support increased renewable energy development and from interconnection of other viable generation projects that hold unfavorable queue positions today could prevent achievement of Colorado state renewable energy standards.

Xcel Energy thus believes additional reforms are needed to enhance the effectiveness of the LGIP to ensure more timely and equitable interconnections to the PSCo transmission system. This is particularly true because it is anticipated that Colorado, like the Midwest ISO and SPP regions, could develop into a region where

V. CONCLUSION

Wherefore, Xcel Energy respectfully requests that the Commission accept these Comments in this proceeding out-of-time.

Respectfully submitted,

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APPENDIX E – EXPLORING CONTROL AREA EXPANSION AND OTHER WAYS TO ADDRESS VARIABLE GENERATION OUTPUT

Public Service is subject to operating reliability criteria by the North American Electric Corporation (NERC) and the Western Electricity Coordinating Council (WECC). Operating reserves are defined by NERC as: "That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve." Spinning reserves are defined as: "Unloaded generation that is synchronized and ready to serve additional demand." Non-spinning reserves are defined as: "That generating reserve not connected to the system but capable of serving demand within a specified time and interruptible load that can be removed from the system in a specified time."

The WECC Minimum Operating Reliability Criteria ("MORC") document and the WECC Standard BAL-STD-002-0 (also a NERC Standard) establish that each Balancing Authority ("BA") shall maintain sufficient operating reserve, comprised of regulating reserve and contingency reserve, to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies. The MORC document states that at a minimum each BA shall maintain regulating reserves in a sufficient amount to "allow the control area to meet NERC's *Control Performance Criteria*" (BAL-001-0). The BA also must maintain sufficient contingency reserves, which includes an "amount of spinning and non-spinning reserve (at least half of which must be spinning), sufficient to meet the NERC Disturbance Control Standard ("DCS") BAL-002-2". The requirements in the MORC document go on to establish that the contingency reserve requirement for a Balancing Authority or Reserve Sharing Group "shall be at least the greater of (1) the loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency (at least half of which must be spinning reserve); or (2) The sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation (at least half of which must be spinning reserve)." Lastly for the "generation-based reserves, only the amount of unloaded generating capacity that can be loaded within ten minutes of notification can be considered reserve."

Public Service maintains operating reserves for compliance with NERC, MORC and WECC standards, and has done so over a time period where wind penetration has significantly increased. Public Service's *Wind Curtailment Operating Policy* establishes a requirement that any loss of wind generation shall be mitigated within 30 minutes. In order to meet this requirement, Public Service dispatches generation such that the amount of real-time wind generation is supported by 30-minute reserves on a one-to-one basis. This protects against system deficiency for potential sudden drop-off in wind output. Public Service has sufficient dispatchable resources to support the current wind portfolio. Public Service's proposed Resource Plan adds the necessary dispatchable resources to provide reserves as described in this plan. Wind integration also requires a new type of system response. Notice the standard definitions of reserves only contemplate the ability to recovery from a deficiency due to loss of output. Our experience with wind resources indicates increasing need for flexibility to manage sudden *increases* in generation output from the wind.

Public Service is increasing its capability to deal with sudden increases in wind output through several means. Excessive generation output is not generally as dire as a shortfall situation from a reliability perspective, but the reliability standards do require balance, not just dealing with shortages. Therefore, we are reviewing our traditional generating assets for increased ramp rate and we are in the early stages of exploring generation "puts" with other utilities, something analogous to the inverse of reserve sharing.

Public Service does not believe that its wind resource portfolio has introduced a reliability risk. With the current resources we have to manage the intermittency of wind, such as Cabin Creek pumped storage, dispatchable resources, and the Wind Curtailment Operating Policy, Public Service is able to meet WECC and NERC reliability standards. In this regard, qualified interruptible loads may contribute to non-spinning operating reserves. This includes the 10-minute curtailable customer load that is qualified under the Public Service Interruptible Service Option Credit tariff as well as the Cabin Creek pump motor load. Cabin Creek is especially dynamic in that it is capable of providing non-spinning reserve while in a pump mode and while in a ready stand-by state, as well as being eligible to provide spinning reserve while synchronized in the generation mode.

There are two types of control area expansion: actual and virtual. Expansion of Public Service's actual control area is pragmatically difficult, as contiguous control areas would need to agree to cede some control to a larger or different control entity. The largest control area contiguous to Public Service is Western Area Power Administration (WAPA), which has not indicated any interest in joining Public Service's control area. In fact, WAPA's stakeholder customers just rejected a proposal to attempt control area consolidation within several branches of the organization.

The second method of expanding Public Service's control area is to do so on a virtual basis. In a virtual control area, each Balancing Authority maintains control of their respective systems, but the systems are directly interconnected, which allows negative and positive adjustments to cancel each other.

Public Service notes that it is a signatory to the WestConnect Project Agreement for Subregional Transmission Planning, which established the WestConnect subregional planning process, including the Colorado Coordinated Planning Group (CCPG). The CCPG provides the technical forum required to complete reliability assessments, develop joint business opportunities, and accomplish coordinated planning, under the single-system planning concept in the Rocky Mountain Region of the Western Electricity Coordinating Council.

WestConnect has created the Virtual Control Area Work Group (VCAWG) to investigate methods and technology available for coordinating control area operations to allow participating Control Areas to function as a Virtual Control Area. VCAWG will also assess the costs associated with implementing any coordinated operations as well as potential cost savings, particularly in the areas of regulation and provision of other ancillary services. The group will develop recommendations along with supporting data for presentation to the WestConnect steering committee.

In addition, the U.S. Department of Energy (DOE) and the National Renewable Energy Laboratory (NREL) are conducting the Western Wind Integration Study, which will examine the operating impacts and mitigation options due to the variability and uncertainty of wind and solar power on the utility grids for several states in the west. This is the largest regional wind integration study undertaken to date. The study will address issues such as:

- Is it more cost-effective for Arizona to use in-state wind resources or import better class resources from out-of-state?
- What are benefits of geographical diversity of wind and solar resources, e.g., for long-distance transmission of wind from Wyoming, Colorado and New Mexico to serve Las Vegas?
- What are the benefits of balancing area cooperation to manage variability?
- What is the role and value of wind and solar forecasting?
- How do wind and solar contribute to reliability and capacity value?
- How can hydro help with wind and solar integration?

This study will investigate significant penetrations of wind and solar on the grid, in line with the Western Governor's Clean and Diversified Energy Initiative of 30 GW clean energy by 2015 and the President's Advanced Energy Initiative that says wind can supply up to 20% of US electricity consumption. A stakeholder meeting is scheduled for August 14, 2008 to discuss study progress. NREL and DOE will then examine costs due to regulation, load following, and unit commitment, and examine mitigation strategies/options, determine contributions to reliability and capacity value. Preliminary technical results are expected by the end of 2008 and a report is expected by the mid-2009 stakeholder meeting.

Public Service will continue to participate in and study the results of the efforts of WestConnect, NREL and DOE to identify opportunities to expand control areas, if feasible and within the best interests of customers.

Lastly on this topic, Public Service supports a development which is underway at a national level to accomplish many of the benefits of virtual control area consolidation. The North American Electric Reliability Council (NERC) has a standard drafting team which is developing a "Reliability-Based Control Standard." This proposed standard makes technical changes to the existing control area balancing standards. When a balancing area is long or short locally (due to wind variability or any other reason) but that error provides support to the overall balance of the interconnection, the balancing control limits are relaxed. Conceptually this achieves many of the benefits of a control area and makes the effect available to all control areas in the interconnection. This standard is undergoing field trial evaluations, and is still likely a few years away from implementation.

APPENDIX F – ESSENTIAL ELEMENTS OF C.R.S. § 29-20-108

Pursuant to C.R.S. § 29-20-108(5), a utility may appeal to the Public Utilities Commission a local government decision relating to the location, construction, or improvement of major electrical or natural gas facilities[1], if the local government denies an application or imposes requirements or conditions upon such application that will unreasonably impair the ability of the public utility or power authority to provide safe, reliable, and economical service to the public, so long as one or more of the following conditions exist:

> (I) The public utility or power authority has applied for or has obtained a certificate of public convenience and necessity from the public utilities commission pursuant to section 40-5-101, C.R.S., to construct the major electrical or natural gas facility that is the subject of the local government action;
>
> (II) A certificate of public convenience and necessity is not required for the public utility or power authority to construct the major electrical or natural gas facility that is the subject of the local government action; or
>
> (III) The public utilities commission has previously entered an order pursuant to section 40-4-102, C.R.S., that conflicts with the local government action.

Prior to an appeal being brought, the utility must comply with § 29-20-108(4), by notifying the affected local government of its plans to site a major electrical or natural gas facility within the jurisdiction of the local government prior to submitting the preliminary or final permit application. Following such notification, the utility shall consult with the affected local government to identify the specific routes or geographic locations under consideration for the site of the facility and attempt to resolve land use

[1] "[M]ajor electrical or natural gas facilities" includes substations, transmission lines of 69 kV or above, and structures and equipment associated with electrical generating facilities. C.R.S. § 29-20-108(3)(b),(c),(d).

issues that may arise from the contemplated permit application. Further, in addition to its preferred alternative within its permit application, the utility shall consider and present reasonable siting and design alternatives to the local government or explain why no reasonable alternatives are available.

The factors the PUC must balance in such an appeal are set forth in C.R.S. § 29-20-108(5)(d). Generally, the PUC shall balance the local government interest with the statewide interest in the location, construction, or improvement of the major electrical or natural gas facilities. In striking such balance, the PUC shall render a decision that is consistent with article 65.1 of title 24, C.R.S., including section 24-65.1-105[2], C.R.S., and the commission shall consider the following factors:

> (I) The demonstrated need for the major electrical or natural gas facility;
>
> (II) The extent to which the proposed facility is inconsistent with existing applicable local or regional land use ordinances, resolutions, or master or comprehensive plans;
>
> (III) Whether the proposed facility would exacerbate a natural hazard;
>
> (IV) Applicable utility engineering standards, including supply adequacy, system reliability, and public safety standards;

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2 C.R.S. § 24-65.1-105 provides:

> (1) With regard to public utilities, nothing in this article shall be construed as enhancing or diminishing the power and authority of municipalities, counties, or the public utilities commission. Any order, rule, or directive issued by any governmental agency pursuant to this article shall not be inconsistent with or in contravention of any decision, order, or finding of the public utilities commission with respect to public convenience and necessity. The public utilities commission and public utilities shall take into consideration and, when feasible, foster compliance with adopted land use master plans of local governments, regions, and the state.
>
> (2) Nothing in this article shall be construed as enhancing or diminishing the rights and procedures with respect to the power of a public utility to acquire property and rights-of-way by eminent domain to serve public need in the most economical and expedient manner.

(V) The relative merit of any reasonably available and economically feasible alternatives proposed by the public utility, the power authority, or the local government;

(VI) The impact that the local government action would have on the customers of the public utility or power authority who reside within and without the boundaries of the jurisdiction of the local government;

(VII) The basis for the local government's decision to deny the application or impose additional conditions to the application;

(VIII) The impact the proposed facility would have on residents within the local government's jurisdiction including, in the case of a right of way in which facilities have been placed underground, whether those residents have already paid to place such facilities underground, and if so, shall give strong consideration to that fact; and

(IX) The safety of residents within and without the boundaries of the jurisdiction of the local government.

APPENDIX G - FEDERAL-STATE JURISDICTIONAL SPLIT OF AUTHORITY AND ACTIONS TAKEN BY FERC OVER ELECTRIC TRANSMISSION MATTERS

A. The Federal Power Act and Transmission of Electric Energy in Interstate Commerce

Enacting the Federal Power Act ("FPA"), 16 U.S.C. § 824, *et seq.*, Congress found that the business of transmitting and selling electric energy to the public is "affected with a public interest." The FPA applies to, and gives the Federal Energy Regulatory Commission ("FERC") the authority to regulate, the transmission of electric energy in interstate commerce. 16 U.S.C. § 824(b).[1] FERC has jurisdiction over the rates charged by any public utility for or in connection with the transmission of electric energy that are subject to FERC's jurisdiction. 16 U.S.C. § 824d(a). The FPA requires that all rules and rates and regulations affecting or pertaining to such charges must be just and reasonable. *Id.*[2] Effectively, these provisions give FERC jurisdiction over the rates, terms and conditions of transmission service by public utilities other than that provided as part of bundled retail electric service.

B. Order No. 888 and Open Access

In April 1996, FERC adopted Order No. 888,[3] requiring public utilities to provide access to their transmission systems comparable to their own use of the systems.

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1 For purposes of the FPA, "electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof." 16 U.S.C. § 824(c).

2 Modeled on the Interstate Commerce Act, the FPA requires regulated utilities to file rate schedules with FERC, and to provide service to electricity purchasers on the terms and prices set forth therein.

3 *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmission Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (19997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002) ("Order No. 888").

Order No. 888 required all public utilities that own, control, or operate facilities for transmitting electric energy in interstate commerce to file open access non-discriminatory transmission tariffs ("OATTs") that contain minimum terms and conditions of non-discriminatory service. Each public utility was required to file the *pro forma* OATT included in Order No. 888 without deviation. After the effectiveness of the OATTs, public utilities were permitted to file deviations that were "consistent with or superior to" the *pro forma* OATT's terms and conditions.

C. Functional Separation

In addition to FERC's open access requirements, Order No. 888 required public utilities subject to its jurisdiction to "functionally unbundle" their generation and transmission services. The transmission element of a wholesale power sale was to be separated or "unbundled" from the generation element of a sale, even though the public utility may provide both functions. Public utilities were required to take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs, and to separately state their rates for wholesale generation, transmission and ancillary services.

The same day that FERC issued Order No. 888, it issued a companion order, Order No. 889[4], addressing the separation of vertically-integrated utilities' transmission and merchant functions, the information transmission providers were required to make public, and the electronic means they were required to use to do so. Order No. 889 imposed Standards of Conduct governing the separation of, and communications between, the utility's transmission and wholesale power functions, to prevent the utility

4 *Open Access Same-Time Information System and Standards of Conduct*, 61 Fed. Reg. 21,737 (1996) (subsequent history omitted).

from giving its merchant arm preferential access to transmission information. All public utilities that owned, controlled, or operated facilities used in the transmission of electric energy in interstate commerce were required to create or participate in an Open Access Same-Time information System ("OASIS") that was to provide existing and potential transmission customers the same access to transmission information. Generally speaking, communications between a utility's transmission and merchant functions outside of OASIS were prohibited.

Order No. 888 also reaffirmed that FERC has exclusive jurisdiction over the rates, terms and conditions of unbundled retail transmission in interstate commerce by public utilities; however, FERC declined to extend its unbundling requirement to the transmission component of bundled retail sales. On appeal, the U.S. Supreme Court affirmed this aspect of Order No. 888, finding that FERC made a choice permissible under the FPA.[5]

D. Order No. 890's Planning Obligations

Order No. 888 recognized that transmission planning is a critical function under the *pro forma* OATT because it is the means by which customers consider and develop access to new sources of energy and have an opportunity to explore the feasibility of non-transmission alternatives; however, there was no affirmative obligation on transmission providers to coordinate with their customers in transmission planning, or to otherwise coordinate planning activities with other transmission providers in their region.

5 *New York v. FERC*, 535 U.S. 1 (2002).

In February 2007, FERC issued Order No. 890,[6] which, among other things, requires transmission providers to participate in a coordinated, open, and transparent planning process on both a local and regional level. Order No. 890 directed transmission providers to submit a compliance filing describing their proposals for a coordinated and regional planning process that complies with the planning principles and other requirements of Order No. 890.[7] According to FERC, planning-related reforms were necessary in order to limit opportunities for undue discrimination and to ensure that comparable transmission service is provided by all public utility transmission providers. The transmission planning process must be documented as an attachment to the transmission provider's OATT. Thus, FERC is asserting authority over a utility's transmission planning process.

Xcel Energy Services Inc. submitted its transmission planning process on behalf of Public Service Company of Colorado ("PSCo") and Southwestern Public Service Company ("SPS") to FERC on December 7, 2007. On July 11, 2008, FERC accepted the filing with regard to SPS, but stated that the planning process for PSCo would be addressed in a subsequent order. *Xcel Energy Services Inc. – Southwestern Public Service Co.*, 124 FERC ¶ 61,029 (2008).

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6 *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), 118 FERC ¶ 61,119 (2007), *order on reh'g*, Order No. 890-A, 73 Fed. Reg. 2,984 (Jan. 16, 2008), 121 FERC ¶ 61,297 (2007); *order on reh'g*, Order No. 890-B, 73 Fed. Reg. 39,092 (July 8, 2008), 123 FERC ¶ 61,299 (June 23, 2008).

7 FERC identified nine planning principles that must be satisfied for a transmission provider's planning process to be considered compliant with that order: (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional participation, (8) economic planning studies, and (9) cost allocation.

E. EPAct 2005 and Siting of Transmission Lines

Enacted on August 5, 2005, the Energy Policy Act of 2005 ("EPAct 2005")[8] added a number of new authorities and priorities for FERC. Among other things, Congress recognized the importance of infrastructure development and its role in facilitating the development of wholesale markets. The directives in EPAct 2005 are intended to reverse the decline in transmission infrastructure development, including through the establishment of incentive ratemaking for transmission infrastructure to help promote reliability and reduce congestion,[9] as well as giving FERC certain "backstop" transmission siting authority that could override state authority.[10] EPAct 2005's new section 216 of the FPA requires the Secretary of the Department of Energy to identify certain transmission constraints. FPA section 216(b) provides that FERC may issue permits to construct or modify electric transmission facilities in certain constrained areas designated by the Secretary ("National Corridors") under certain circumstances.[11]

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8 Pub. L. No. 109-58, 119 Stat. 594 (2005).

9 16 U.S.C. § 824s. With this authority, FERC has promulgated a Final Rule, *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006), FEC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, 72 Feed. Reg. 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

10 16 U.S.C. § 824p. With regard to siting of transmission lines, FERC has promulgated a Final Rule, *Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Facilities*, Order No. 689, 71 Fed. Ref. 69,440 (Dec. 1, 2006), FERC Stats. & Regs. ¶ 31,234 (2006), *order on reh'g*, 119 FERC ¶ 61,154 (2007).

11 FERC has the authority to issue permits to construct or modify electric transmission facilities if it finds that: (1) a State in which such facilities are located does not have the authority to approve the siting of the facilities or to consider the interstate benefits expected to be achieved by the construction or modification of the facilities; (2) the applicant is a transmitting utility but does not qualify to apply for siting approval in the State because the applicant does not serve end-use customers in the State; or (3) the State commission or entity with siting authority withholds approval of the facilities for more than one year after an application is filed or one year after the designation of the relevant national interest electric transmission corridor, whichever is later, or the State conditions the construction or modification of the facilities in such a manner that the proposal will not significantly reduce transmission congestion in interstate commerce or is not economically feasible.

APPENDIX H - DESCRIPTION OF ONGOING REGIONAL AND STATE ACTIVITIES ON TRANSMISSION MATTERS

WECC membership is divided into classes based on stakeholders' interest in the region. The Class 5 membership is made up of regulators across the footprint. Specifically, the WECC bylaws, section 4.2.5 define Class 5 as: "Representatives of states and provinces in the Western Interconnection, provided that representatives will have policy or regulatory roles and do not represent state or provincial agencies and departments whose function involves significant direct participation in the market as end users or in Electric Line of Business Activities."

Regulators from the western states and provinces participate in varying degrees. Seated on the WECC board, and having considerable influence in WECC matters are three state commissioners including Marsha Smith (Idaho PUC and NARUC President), Lee Beyer (Oregon PUC), and Ric Campbell (Utah PSC). In addition, William Chamberlain of the California Energy Commission serves on the Board of Directors as a Class 5 representative.

The WECC Board meets four times a year and helps shape transmission policy matters throughout the West. In addition to the Board meetings, various state commissioners and commission staff are members of other groups within WECC that directly impact transmission issues. These groups include the Reliability Policy Issues Committee, the Market Interface Committee, the Operating Committee, and the PCC.

In other regions where Xcel Energy operates, there are more organized markets under RTO and ISO models. In those regions, regulators take a more active role in transmission matters and most specifically in cost allocation matters.

In the Southwest Power Pool (SPP), the RSC provides collective state regulatory agency input on matters of regional importance related to the development and operation of bulk electric transmission. The SPP RSC is comprised of retail regulatory commissioners from agencies in Arkansas, Kansas, Missouri, New Mexico, Oklahoma, and Texas. This committee also has subcommittees made up of commission staff from each state to specifically address regional pricing and cost allocation matters that arise from region RTO operations and transmission expansion. Also, utilities from the state of Nebraska are reportedly planning to join the SPP region sometime in the spring of 2009.

The RSC operates in parallel to the SPP Board of Directors, providing guidance to that Board and making comments to outside entities, including FERC, on matters affecting pricing and cost allocation.

Within the MISO footprint exists the Organization of MISO States (OMS). The purpose of the OMS is to coordinate regulatory oversight among the states; making recommendations to the MISO, the MISO Board of Directors, the FERC, other relevant government entities, and state commissions as appropriate; and intervening in proceedings before the FERC and in related judicial proceedings to express the positions of the OMS.

The Advisory Committee of the MISO makes recommendations and provides advice to MISO management and the Board of Directors. From the Transmission Owners Agreement, which has been approved at FERC, it is clear that it is advice, and there is no obligation that the advice be taken nor is any action taken in the Advisory Committee process binding on any state commission. There are now three seats designated for state regulatory commissions on the Advisory Committee. The formation of the OMS, with full-time staff since early 2004, has allowed better coordination and support for the state commission Advisory Committee representatives. Nevertheless, these representatives play an important role in expressing the viewpoints of the state regulatory community to MISO and its members.

Public Service would be remiss not to mention Colorado-specific transmission meetings expected in the near future based on a letter agreement with stakeholders in Docket No. 07A-421E (the Company's application for authority to construct the Pawnee-Smoky Hill 345 kV Transmission Line Project). The Pawnee-Smoky Hill Project that is the subject of Docket No. 07A-421E will allow for the injection of an additional 500 MW of generation capacity from Zone 1 at Pawnee Substation, but will be insufficient to accommodate generation resources in excess of 500 MW or generation resources to be injected in Zone 1 at points other than Pawnee Substation. Accordingly, Public Service agreed to continue its work to further study and develop appropriate applications for CPCNs for transmission projects necessary to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near Zones 1, 2, 3 and 4 in accordance with the following schedule:

1) March 4, 2008 – Initial meeting of Transmission Study Group:

a. Discuss Generation Development Areas (GDA) identified in the SB07-091 report issued by the Governor's Energy Office in December 2007
b. Discuss 2015 benchmark case
c. Establish schedule for monthly meetings
d. Post agenda and minutes on the Company's web site for SB07-100
e. Identify additional invitees, including, but not limited to, proponents of community wind projects, agencies within potentially affected local governments charged with responsibility for land use regulation and agencies and other organizations interested in wildlife issues

2) April through July 2008 - Transmission Study Groups will meet

3) November 1, 2008 - Issue transmission study reports for transmission projects that will alleviate transmission constraints from Zones 1, 2, 3 and 4.

4) November 2008 – January 2009: The Company agreed to perform detailed studies, necessary to support appropriate CPCNs for Zones 3 and 4, and Zones 1 and 2, if it appears reasonably likely that additional transmission will be required to accommodate new generation expected to come on line before 2015 located in those areas.

5) March 1, 2009 – Public Service shall file applications for CPCNs to construct transmission necessary to accommodate potential new generation resources located in Zones 1, 2, 3 and 4 reasonably likely to come on line by 2015.

6) October 31, 2009 – Public Service agreed to file transmission plans as part of its SB07-100 transmission planning report for transmission required to accommodate potential new generation resources to be located an all identified Energy Resource Zones through 2018.

7) In developing its transmission plans for both the 2015 benchmark case and for the 2018 transmission planning report, the Company agreed to consult with the Colorado Division of Wildlife and the U.S. Fish and Wildlife Service regarding the potential impact of its transmission plan on listed wildlife species as well as species and habitats of concern and to identify any concerns raised by those agencies in the transmission plan. This consultation shall occur within a reasonable time after specific corridors have been identified as reasonably likely routes for planned new transmission projects.

The transmission study group is developing transmission plans that would provide desired transfer capability increases from each zone to the major load center in the Front Range of Colorado and the Denver Metro area. This study group meets weekly to evaluate plans in the 2015 target time frame, which is coincident with the Colorado Resource Plan.

Additionally, all utilities in the Colorado-Wyoming region are participating in an effort to evaluate a 2018 plan as part of the Colorado Long Range Planning Group. This group also meets regularly with utilities and stakeholders. Even given the customary ten-year planning horizon being utilized here, these two efforts are proceeding slowly due to the challenges inherent in managing and coordinating a multi-party planning effort, which naturally involves extensive debate and uncertainty over assumptions, including loads and resources. In these efforts, Commission Staff has been at the table and able to participate on par with the transmission providers and stakeholders. What is significant about these efforts is that this is a coordinated overall effort and not just an isolated or single project discussion. The result will be the publication of the third Colorado Long Range Transmission Plan produced in the last four to five years.

Public Service and other utilities are also engaged in an additional set of planning studies for 2013 and 2018 through WestConnect. The WestConnect regional planning effort has developed over the last three years through the dedication of WestConnect members to making this planning effort broad, transparent, and inclusive of stakeholders.

Public Service encourages direct Commissioner participation in local and regional transmission group meetings. As Public Service moves forward with its transmission planning, it will be helpful to know the Commission's (and Commissioners') views on the various issues discussed in these Comments.