MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
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July 27, 2007

Executive Secretary
North Dakota Public Service Commission
State Capitol Building
Bismarck, ND 58505

Re: In the Matter of the Advance Determination of Prudence Application - Late Filed Exhibits of Otter Tail Corporation Case No. PU-06-481

In the Matter of the Advance Determination of Prudence Application - Late Filed Exhibits of Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. Case No. PU-06-482

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., and Otter Tail Corporation, herewith submits an original and seven (7) copies of Applicants' Responses to Requests for Late Filed Exhibits with the exception of Late Filed Exhibit No. 7 which contains trade secret information and will be transmitted under separate cover by Otter Tail Corporation.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed stamped envelope.

Sincerely,

Donald R. Ball

Donald R. Ball
Vice President – Regulatory Affairs

Attachments
cc: Service List

224 PU-06-482 Filed 07/27/2007 Pages: 19
Applicants Responses to Requests for Late Filed Exhibits, except Ex No. 7
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Otter Tail Corporation, Advance Determination of Prudence Late Filed Exhibits

SERVICE LIST

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., Advance Determination of Prudence Late Filed Exhibits

Case Nos. PU-06-481, PU 06-482

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STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Otter Tail Corporation, Advance Determination of Prudence Late Filed Exhibits	**AFFIDAVIT OF SERVICE**
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., Advance Determination of Prudence Late Filed Exhibits	Case Nos. PU-06-481, PU 06-482

Sara Graf, of Bismarck North Dakota, being sworn, says that on July 27, 2007, a copy of the Late Filed Exhibits, with the exception of Late Filed Exhibit Number 7, in the above referenced cases, has been served upon the North Dakota Public Service Commission and the attached service list via email.

Sara Graf

Sara Graf

Subscribed and sworn to before me this 27th day of July, 2007.

Norma E. Eslinger

Notary Public

NORMA E ESLINGER
Notary Public
State of North Dakota
My Commission Expires August 30, 2011

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Otter Tail Corporation and Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., Advance Determination of Prudence Application

APPLICANTS' RESPONSES TO REQUESTS FOR LATE FILED EXHIBITS BY THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

Case Nos. PU-06-481, PU 06-482

Otter Tail Corporation & Montana-Dakota Utilities Co.
Case Nos. PU-06-481 & PU-06-482
Advance Determination of Prudence – Big Stone II Generating Station
Late Filed Exhibit No. 1

Montana-Dakota's list of supply side options including Big Stone II. The list should include the cost of each supply option. Montana-Dakota's list of current DSM programs in any jurisdiction, and list of DSM programs identified in 2007 IRP. The lists should include the cost of implementing each of the DSM programs in North Dakota. If any of this information is in the current 2007 IRP, please refer us to specific pages.

Response:

The list of supply side options Montana-Dakota considered in the resource expansion analysis for its integrated system is provided as Table 4-1 in Montana-Dakota's Exhibit No. MDU-211 "Generation Expansion Plan Analysis" October 2, 2006. The characteristics of the generation expansion options considered are shown in Table 4-1 reproduced below. The characteristics include fuel type, the year the option may be available (and therefore available for the model to choose), cost data and assumed operating data.

Unit	Fuel	Years Available	Capacity (MW)	Capital Cost $/Kw (2006)	Full Load Heat Rate (Bt/Kwh)	Fuel Price ($/MMBTU)	Variable Cost $/Mwh	Fixed Cost $/Kw (2006)	Planned Maint. Wks/Yr	FOR (%)
Combustion Turbine	Natural Gas	2008-2025	43	916	9,000	7.37	4	32.22	2	3
Combined Cycle	Natural Gas	2009-2025	130	1,668	7,550	7.37	4	18.85	2	3
Bigstone II	Coal	2012-2025	116	2,461	9,600	1.52	2	27.70	4	5
Wind	Wind	2008-2025	50	1,500			5	25.00		
IGCC	Coal	2015-2025	116	2,668	9,612	1.07	6	24.15	4	5
Lignite Coal	Coal	2012-2025	116	2,745	10,440	1.28	3	46.72	4	5

The following Demand Side Management (DSM) programs were also considered to be available as a resource in the October 2006 Expansion Plan Analysis presented in MDU Exhibit 211. The DSM options are shown in Table 4-2 of MDU Exhibit 211:

- DSM Option 1 consisted of a residential and commercial air conditioning cycling program identified in the 2005 Integrated Resource Plan (IRP) as Option B. This was in addition to the DSM reflected as an offset to the forecasted load requirements which are from two DSM programs implemented in 2006; Residential High Efficiency Air Conditioning Program and the Commercial Lighting T-8 Retrofit Program identified in the 2005 IRP as Option A, plus the interruptible load provided under the North Dakota interruptible rate program. The two DSM programs implemented in 2006 were expected to provide a capacity reduction of 6.47 MW with the interruptible rate program in place in North Dakota providing 5.5 MW of interruptible load. As previously noted, the estimated energy and capacity savings associated with programs in place in 2006 were accounted for as a reduction in the forecasted requirements and therefore not considered as an incremental resource in the integration process.
- DSM Options 2 and 3 consisting of two increments of 10 MW each to be available as resource options at a cost of $470 per KW and $560 per KW respectively were also considered in the October 2006 Expansion Plan Analysis.

As shown on Table 5-1 in MDU Exhibit 211, the optimal expansion plan picked Big Stone II in 2012 with the additional DSM chosen for implementation in 2014 and 2015.

In developing the 2007 IRP, the Company, along with the IRP Public Advisory Group (PAG) identified fourteen potential DSM programs for exploration. In order to balance all interests and achieve cost-effective DSM for the utility, customers/ratepayers and society as a whole, a cost-benefit analysis from different perspectives was performed on potential DSM programs. The perspectives or "tests" are not intended to be used individually or in isolation, and must be compared to each other. This multi-perspective approach allows consideration for tradeoffs between various tests, however the impacts measured from the customer/ratepayer perspective and societal perspective will determine if a program is feasible. Once a program is determined feasible, all test results are considered to determine if a program should be implemented. Therefore, even if a program is feasible, it may not be implemented due to tradeoffs with other tests and other identified factors. An example would be the program analyzed to encourage customers to replace a conventional clothes washer with a higher efficient Energy Star© rated unit through the use of a rebate. The program produces positive results with the majority of the savings attributable to the savings in water heating. However, given the limited market potential for electric water heating on Montana-Dakota's system, it was determined that the time required marketing the program could not be economically justified.

Based on the benefit/cost analysis and the practicality of installation, the following nine programs have been identified as beneficial DSM programs and will be implemented:

1. ENERGY STAR® refrigerator rebates
2. ENERGY STAR® freezer rebates
3. Residential air conditioning cycling program

4. Refrigerator round-up program
5. Interruptible Demand Response Rate in North Dakota, South Dakota and Montana
6. High efficiency motor rebates
7. ENERGY STAR® commercial central air conditioner rebates
8. Commercial air conditioner cycling program
9. Light-emitting diode (LED) exit sign lighting rebates

The new DSM programs will provide Montana-Dakota an estimated additional demand reduction of 13.8 MW once implementation is complete. The total DSM program cost will be approximately $344/Kw. The first year program costs are estimated to be approximately $1,988,179, with a total estimated cost of approximately $4,747,576 over the implementation period.

Montana-Dakota does not model the programs for implementation in a particular state but plans for implementation throughout the integrated system. Therefore, specific costs to North Dakota will be dependent upon actual participation by North Dakota customers plus an allocation of start up costs.

Following is a summary table of the existing and new DSM programs described above.

Programs	Available Date	Annual kWh Savings	Peak kW Savings	Installed Cost/kWh	Installed Cost/kW
Conservation Programs:					
Residential High Efficiency A/C	2006	634,029	771	$0.022	$277
Commercial Lighting	2006	2,848,560	5,694	$0.012	56
ENERGY STAR® Refrigerators	2008	312,191	195	$0.027	636
ENERGY STAR® Freezers	2008	175,574	127	$0.042	867
Refrigerator Round-Up	2008	473,999	503	$0.034	324
LED Exit Signs	2008	86,944	124	$0.014	971
Residential A/C Cycling	2009	238,782	7,151	$0.126	419
Commercial A/C Cycling	2009	29,157	873	$0.126	421
Commercial High Efficiency A/C	2008	203,689	199	$0.054	835
High Efficiency Motors	2008	567,063	138	$0.017	1,045
Total Conservation Related		5,569,988	15,775		
Load Management Programs:					
IT Rate - Demand Response ND 1/	2007	417,853	5,530	$0.163	123
IT Rate - Demand Response MT, SD	2009	340,025	4,500	$0.163	123
Total Load Management		757,878	10,030		
Total		**6,327,866**	**25,805**		

1/ Montana-Dakota has had an interruptible rate in place in North Dakota since 1984. This reference is to a new rate implemented in 2007.

As shown on Table 5-1 of Attachment C to the 2007 IRP, the expansion plan analysis chooses the DSM programs noted above (with the exception of the Interruptible Demand Response rates for Montana and South Dakota) along with a baseload supply source in 2012. As explained in the 2007 IRP, Montana-Dakota will pursue the addition of the Interruptible Demand Response rates in Montana and South Dakota in lieu of the combustion turbine picked by the expansion plan for 2010.

In summary, Montana-Dakota's optimal resource plan, as of July 1, 2007, identified through the IRP process for the Year 2012 consists of 25.8 Mw of DSM (12 Mw of which is reflected as a reduction in the forecasted requirements and 13.8 incremental DSM); 110.8 Mw of existing peaking resources; 20 Mw wind and 488.3 Mw of coal fired baseload generation comprised of existing resources plus 116 Mw of the Big Stone II plant. This mix of resources produces the least cost to Montana-Dakota's customers over the long term planning horizon necessary to reliably serve customers.

Otter Tail Corporation & Montana-Dakota Utilities Co.
Case Nos. PU-06-481 & PU-06-482
Advance Determination of Prudence – Big Stone II Generating Station
Late Filed Exhibit No. 2

Cost to Otter Tail's and Montana-Dakota's customers of coal supply disruptions at Big Stone I.

Response:

Otter Tail: The cost to Otter Tail Power's customers associated with coal supply disruptions to Big Stone 1 in 2006 was estimated at $2,836,500 in total with $1,134,600 allocated to Otter Tail Power Company's North Dakota customers.

Montana-Dakota: The cost to Montana-Dakota's customers associated with coal supply disruptions to Big Stone 1 in 2006 were estimated at $1,018,000 in total, with $627,925 allocated to Montana-Dakota's North Dakota customers.

Otter Tail Corporation & Montana-Dakota Utilities Co.
Case Nos. PU-06-481 & PU-06-482
Advance Determination of Prudence – Big Stone II Generating Station
Late Filed Exhibit No. 3

The total production costs (net energy) of Big Stone I and Coyote per Kwh generated for the twelve months ended December 31, 2006.

Response:

Otter Tail Power Company
Electric Generation Comparison
Big Stone Plant versus Coyote Station
Dollars are in Thousands

	2006	
	Coyote Station	Big Stone Plant
Year Installed:	1981	1975
OTP's Share of MW's	145	223
Total Cost of Construction	$147,319	$123,318
Assumed Rate of Return plus Taxes	15%	15%
Return Required	$22,098	$18,498
Operating Expenses:		
Production	$451	$507
Fuel	$11,425	$26,843
Steam	$1,633	$548
Electric	$452	$768
Miscellaneous Steam	$456	$1,737
Maintenance	$3,516	$3,837
Total Production Expenses	$17,933	$34,240
Total Cost of Production	$40,030	$52,738
Net Generation (kWh)	981,477,885	1,669,980,759
Total Cost of Production per kWh	$0.041	$0.032

Montana-Dakota's total production costs per Kwh for its share of the Coyote and Big Stone generating stations for the twelve months ended December 31, 2006 are shown below.

	2006 $(000's)	
	Coyote	Big Stone
Year installed:	1981	1975
MDU's Share of MW's	104	94
Total Cost of Plant	$117,398	$53,143
Return	10.016%	10.016%
Return Required	$11,759	$5,323
Associated Taxes	7,518	3,403
Total Return & Taxes	$19,277	$8,726
Production Expenses:		
Production	$364	$363
Fuel	8,155	11,751
Steam	1,171	231
Electric	322	323
Miscellaneous Steam	351	494
Maintenance	2,505	1,617
Total Production Expenses:	$12,868	$14,779
Total Cost of Production	$32,145	$23,505
Net generation (mWh)	701,413	727,347
Total Cost of Production per kWh	$0.046	$0.032

Otter Tail Corporation & Montana-Dakota Utilities Co.
Case Nos. PU-06-481 & PU-06-482
Advance Determination of Prudence – Big Stone II Generating Station
Late Filed Exhibit No. 4

Montana-Dakota's cost and quantity of energy purchases from the Midwest ISO energy market for the summer of 2006 and summer of 2007 to present, by month.

Response:

Shown below are the quantities purchased by Montana-Dakota and the average purchase price.

2006 Summer Purchases

	Mw's Purchased	Avg $/MW
May	11,105	$46.53
June	7,699	60.66
July	4,866	97.72
August	836	77.98
September	3,956	33.04

2007 Summer Purchases to Date

	Mw's Purchased	Avg $/MW
May	16,392	$53.68
June	15,815	51.82

Otter Tail Corporation & Montana-Dakota Utilities Co.
Case Nos. PU-06-481 & PU-06-482
Advance Determination of Prudence – Big Stone II Generating Station
Late Filed Exhibit No. 5

Montana-Dakota's cost of contracted capacity for the summer of 2007.

Response:

Montana-Dakota's cost of contracted capacity applicable during the summer of 2007 is $29.50 per Mw per month for 95 Mw of contracted capacity.

Otter Tail Corporation & Montana-Dakota Utilities Co.
Case Nos. PU-06-481 & PU-06-482
Advance Determination of Prudence – Big Stone II Generating Station
Late Filed Exhibit No. 6

Proposal and description of benefits to consumers regarding Commissioner's Wefald's concept of tying an incentive return to meeting the estimated bus bar cost of BSII including transmission.

Response:

Applicants have considered an incentive return mechanism for meeting the estimated bus bar cost of BSII as suggested by Commissioner Wefald. This included a review of the Metropolitan Emissions Reduction Proposal (MERP) submitted by Xcel to the Minnesota Public Utilities Commission (PUC), the Minnesota Department of Commerce and the Minnesota Pollution Control Agency as a proposal qualifying for emissions reduction-rider treatment under Minn. Stat. §216B.1692. Under the statute, emissions reduction projects may be approved for rate-rider treatment if they are installed on existing generation plants grandfathered under the federal Clean Air Act (CAA); do not increase plant capacity by more than ten percent or 100 MW, whichever is greater; and either comply with CAA new source review (NSR), emit at "substantially lower" levels than allowed for new facilities by CAA new source performance standards (NSPS), or reduce emissions to the lowest cost-effective level when it would not be cost-effective to reach NSR or NSPS levels.

Pursuant to subdivision 3(a) (7) of the statute, the public utility must, if seeking any proposed recovery above cost, include such a proposal in its petition to the PUC. Under subdivision 5(a), the PUC is required to consider whether the project, proposed cost recovery, and any proposed recovery above cost appropriately achieves environmental benefits without unreasonable customer costs. Subdivision 5(b)(4) vests discretion in the PUC to approve a rider that provides a mechanism for recovery above cost "if necessary to improve the overall economics of the qualifying projects to ensure implementation."

The original Xcel MERP proposal would have allowed Xcel its authorized rate of return on common equity of 11.47 percent from its last rate case. A settlement agreement (dated December 11, 2003) with various parties to the docket (which was ultimately approved by the PUC in an order dated March 8, 2004) proposed a sliding scale rate of return that limited the rate of return on the rate rider to 10.86 percent if actual costs were between 95 and 105 percent of target costs, and decreased the rate of return as costs further exceeded target costs. Conversely, where actual overall project costs were reduced relative to target costs, the settlement agreement allowed increasingly higher rates of return on the rate rider, leading to a top rate (11.47 percent) if actual costs were 75 percent or less of target costs.

The BSII project, subject to a prudence determination in this proceeding, is not at a stage for consideration of an incentive return to meet an estimated busbar cost. The

Applicants will both be seeking cost recovery of the BSII generating station, if deemed prudent in this case, in separate proceedings. The issue in this proceeding is whether BSII is a reasonable and prudent generation investment in light of relevant available information. The integrated resource planning (IRP) process is designed to ensure that utilities choose from a menu of options that facilitates an optimal blend of generation resources. IRP generation selections are based on total generation plant life-cycle cost, not just upfront capital cost or first year operating cost.

In addition, the use of a busbar cost concept that subsumes an all-in cost is significantly different than project construction costs to be recovered under a rate rider as used in Xcel's MERP case.

The Applicants, along with the other five participants in the plant have sufficient incentive to do what can be done to construct and operate this plant as economically as possible. By teaming with other companies (including non-profit and public power entities) to spread risk, by utilization of structured bidding processes, and by virtue of the strong desire to remain at or near market on a kWh basis, an ad hoc regulatory cost containment incentive is neither necessary, nor desirable as also suggested by the Commission's Advocacy Staff.

In comparison to the MERP rate rider, the investment in BSII will be made over a longer time period and therefore subject to more factors outside the control of the owners that will affect the final price of BSII and which would likely affect the price of any other generation alternative such as wind generators or a coal fired generator at another location. If savings are realized as result of those factors, the savings will be realized in total by customers over the life of the plant. Likewise, if those factors result in cost increases, the owners should not be penalized for cost factors beyond their control if the decision to construct the plant was otherwise reasonable and prudent when the decision was made. Finally, as we understand, the Xcel rate rider is an immediate relative short term cost recovery mechanism using an incentive adjustment to an established rate of return until Xcel's next rate case. Unless Commissioner Wefald is suggesting a similar immediate cost recovery mechanism outside the rate case process, it would be difficult, if not impossible, at this time to arrive at an equitable incentive adjustment and rate of return to use when BSII becomes part of the Companies' rate base. Indeed, an incentive adjustment to an unknown rate of return that would be established at some time in the future would be of little value. It is also highly doubtful that any agreed incentive adjustment or rate of return could be binding on the Commission in the future particularly as members of the Commission change over the life of the BSII plant.

Otter Tail Corporation & Montana-Dakota Utilities Co.
Case Nos. PU-06-481 & PU-06-482
Advance Determination of Prudence – Big Stone II Generating Station
Late Filed Exhibit No. 8

Otter Tail's load history and forecast (capacity and energy) by jurisdiction.

Response:

Otter Tail has developed a new load forecast available for use as of July 1, 2007. The forecast does not have a breakdown by every state, but does have a breakdown by MN and non-MN jurisdictions. At this time, approximately 52% of retail kWh are sold in MN, 43% in ND, and 5% in SD.

For the 2007 – 2014 period, projected load growth is 2.24% annually for the total system. The MN load growth over that time period is 2.576% annually, and the non-MN annual load growth is 1.88%. The load forecast is done based on raw load, unmanaged and without new conservation. Prior conservation efforts are contained in the forecast, but new conservation efforts are not.

Otter Tail Power Historical Jurisdictional Retail Sales

Year	Minnesota Retail Sales(MWh)	MN Percentage	North Dakota Retail Sales(MWh)	ND Percentage	South Dakota Retail Sales(MWh)	SD Percentage
1985	1,372,522	50.67%	1,130,187	41.73%	205,943	7.60%
1990	1,462,905	52.30%	1,117,391	39.98%	215,899	7.72%
1995	1,761,141	53.86%	1,261,843	38.59%	246,871	7.55%
2000	1,815,003	52.19%	1,395,612	40.13%	266,966	7.68%
2001	1,896,430	52.30%	1,451,830	40.04%	277,641	7.66%
2002	1,914,508	51.78%	1,478,488	39.99%	304,581	8.24%
2003	1,884,900	50.94%	1,499,944	40.54%	315,489	8.53%
2004	1,953,515	51.82%	1,491,673	39.57%	324,779	8.61%
2005	2,018,332	51.71%	1,534,203	39.31%	350,655	8.98%
2006	2,085,660	52.30%	1,537,590	38.56%	364,520	9.14%

Otter Tail Corporation & Montana-Dakota Utilities Co.
Case Nos. PU-06-481 & PU-06-482
Advance Determination of Prudence – Big Stone II Generating Station
Late Filed Exhibit No. 9

Number of customers on BSII rail line served by BNSF.

Response:

There are 83 customers who originated or terminated products by rail in 2006 along our rail line beginning at Terry, Montana and ending at Milbank, South Dakota.

The primary commodities are Agricultural and Coal.

Of the 45,476 carloads that originated or terminated on the line in 2006:

- 61% were Agricultural
- 35% were Coal
- 4% were Industrial Products

Primary origin/destination rail stations in South Dakota are:

- McLaughlin
- Selby
- Bowdle
- Craven
- Aberdeen
- Grebner
- Groton
- Big Stone City

Otter Tail Corporation & Montana-Dakota Utilities Co.
Case Nos. PU-06-481 & PU-06-482
Advance Determination of Prudence – Big Stone II Generating Station
Late Filed Exhibit No. 10

Comparison of transmission costs at Coyote versus Big Stone II.

Response:

The table below summarizes the transmission cost comparison between siting generation at Coyote versus Big Stone.

	Big Stone II	Coyote II
Interconnection	$114,705,678	$200,000,000
Delivery	65,800,000	60,000,000
Escalation	22,170,487	37,000,000
Reserve/Other	35,450,138	53,000,000
Total	$238,126,303	$350,000,000

The assumptions used in developing the costs for the Coyote site are the following:

- Interconnection facilities require 300 miles of new 345 kV transmission, and substation upgrades at Coyote, Jamestown and Fargo. Without having a specific route identified, we estimate that the line could be as short as 270 miles and as long as 330 miles, as a result we selected the average between those options.
- Delivery Service facilities are estimated to be the same for either site. Because no detailed Delivery Service studies were completed for this site, we estimate the cost for transmission upgrades associated with delivery will be similar to the delivery upgrades for Big Stone II.
- The same per unit costs ($/ mile of line) were applied to the Coyote II estimate as were used in the Big Stone II estimate.
- The same reserve fund (unexpected costs increases) philosophy was applied to Coyote II as were used in the Big Stone II estimate.
- The Coyote estimate is likely a best-case scenario (lowest cost), because it does not include the costs associated with the CapX facilities, which may be a requirement for interconnecting and delivering the power out of Coyote.

The biggest reason for the cost difference is the length of the transmission lines required for each alternative. The table below summarizes the estimated line lengths of each project.

	Big Stone II	Coyote II
345 kV Lines	90	300
230 kV Lines	50	0
Total	140	300

In addition to the shorter line length for Big Stone II, of the 140 miles of line construction that is required, about 90 miles will be on an existing transmission line corridor.

Otter Tail Corporation & Montana-Dakota Utilities Co.
Case Nos. PU-06-481 & PU-06-482
Advance Determination of Prudence – Big Stone II Generating Station
Late Filed Exhibit No. 11

Notify the ND PSC when all of the final contracts have been signed for the Langdon Wind Center.

Response:

On February 19, 2007, Otter Tail signed a Power Purchase Agreement with FPL Energy, LLC for the purchase of 19.5 MW. There are four (4) additional agreements that are awaiting final execution regarding Otter Tail's proposed ownership of 40.5 MW of the Langdon Wind Center. These agreements address a variety of issues, including the ownership sharing of facilities, construction management, operation and maintenance, etc. One of the agreements is an option agreement for ownership by Otter Tail of the 40.5 MW. Otter Tail has made the option payment to FPL Energy. Otter Tail also has 27 turbines on order from General Electric (OTP is providing its own turbines, rather than FPL Energy providing them). The agreements await final review and approval from FPL Energy's legal department. Otter Tail originally expected that the agreements would be signed by the middle of July. We expect the agreements will be finalized soon and will update the Commission once the ownership agreements are executed.