



2302 Great Northern Drive
P O Box 2747
Fargo, ND 58108-2747
(701) 241-8632
dave.sederquist@xcelenergy.com

November 1, 2016

--Via Electronic Filing--

Darrell Nitschke, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

RE: PROPOSED 2017 RENEWABLE ENERGY RIDER RATE
CASE NO. PU-16-_____

Dear Mr. Nitschke:

Northern States Power Company, doing business as Xcel Energy, submits to the North Dakota Public Service Commission this application for approval of a revised Renewable Energy Rider (RER) rate designed to recover the 2017 revenue requirements associated with the Company's two wind energy projects located in North Dakota.

The Company wishes to have the revision go into effect January 1, 2017.

The filing fee of \$50 can be taken out of the Company's miscellaneous filing fund.

The proposed new rate of \$0.000898 per kWh is a 4.27 percent decrease from the 2016 rate. The rate impact for the average customer using 750 kWh per month is \$0.67; a decrease of \$0.03 from the current rate.

Please contact me if you have any questions or comments.
Sincerely,

DAVID H. SEDERQUIST
SR. CONSULTANT, REGULATION/FINANCE

Enclosures

**BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA**

IN THE MATTER OF THE APPLICATION OF
NORTHERN STATES POWER COMPANY
FOR APPROVAL OF A 2017 RENEWABLE
ENERGY RIDER RATE

CASE NO. PU-16-____

Application of Northern States Power Company

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the North Dakota Public Service Commission this application for approval of a 2017 Renewable Energy Rider (RER) rate designed to recover the revenue requirements associated with the Company's eligible renewable energy projects. We submit this application pursuant to N.D.C.C. § 49-02, 49-05, and 49-06, which authorizes the Commission to approve rate recovery of investments and expenses related to new or modified renewable energy facilities located in North Dakota.

In this filing we propose to update the RER rate to recover an estimated \$2.03 million based on the 2017 revenue requirements related to the company's two North Dakota wind projects (Border Winds and Courtenay). The resulting rate we propose to implement on January 1, 2017 is \$0.000898 per kWh applied to all energy billed to each customer class. The rate has been calculated to be in place through the end of 2017. The average bill impact is estimated to be \$0.67 per month for a typical residential electric customer using 750 kWh per month. The new rate will be slightly lower than the 2016 rate, reflecting the fact that the current RER rate recovers costs from both 2015 and 2016.

Approval of the Company's use of an RER was established by the Commission's February 26, 2014 *Order Adopting Settlement* in Case No. PU-12-813. The Company began recovering the costs of the two wind projects through the 2016 RER at an approved rate of \$0.000936 per kWh.

In summary, this Petition seeks Commission approval of:

- a true-up of 2015 and 2016 cost recovery for the two wind projects;
- the 2017 RER revenue requirement of \$2,026,203;
- the rate of \$0.000898 per kWh to be implemented January 1, 2017; and
- a revised RER tariff sheet and customer bill message.

I. GENERAL INFORMATION

Pursuant to § 69-02-02-04 of the Commission's Rules of Practice and Procedure, the following information is provided:

A. Name, address, and telephone number of the utility making the filing

Northern States Power Company
2302 Great Northern Drive
PO Box 2747
Fargo, ND 58108-2747
(701) 241-8632

B. Name, address, and telephone number of the attorney for Northern States Power Company

Alison Archer
Assistant General Counsel
Xcel Energy Services Inc.
414 Nicollet Mall 401– 8th Floor
Minneapolis, MN 55401
(612) 215-4662

C. Title of utility employee responsible for filing

David H. Sederquist
Sr. Regulatory and Financial Consultant
2302 Great Northern Drive
PO Box 2747
Fargo, ND 58108-2747

D. Date of filing and proposed effective date

The date of this filing is November 1, 2016. The Company proposes the RER Rate be reflected in the RER charge included in the Company's retail electric billing rates effective January 1, 2017, or in the first full month following Commission approval if Commission action occurs after December 2016¹.

¹ Where implementation is to begin later than January 1, we request the monthly rate be adjusted to recover the approved 2017 revenue requirement over the time the revised rate is in effect in 2017.

E. Articles of Incorporation

Pursuant to North Dakota Rules Part 69-02-02-04, a certified copy of Xcel Energy's Articles of Incorporation is on file with the Commission, as is an original Certificate of Good Standing.

II. BACKGROUND AND PURPOSE OF FILING

The Company has made and will continue to make significant investments in two very low-cost wind energy facilities in North Dakota. These facilities will help keep customer energy bills low, invest in local power generation in the state of North Dakota, further diversify our energy portfolio, and help to keep the state's air quality among the best in the nation. To recover the North Dakota jurisdictional portion of these investments, we propose an RER Rate in this application to be effective January 1, 2017 through December 31, 2017.

N.D.C.C. § 49-05-16 provides a rebuttable presumption that generation resources to be developed in North Dakota are prudent. Further, N.D.C.C. Chs. 49-02, 49-05 and 49-06 and Commission precedent in Case No. PU-06-466² allows for the recovery of costs of renewable resources developed in North Dakota. As approved in Case No. PU-12-813, the Company is permitted to recover costs including, but not limited to, depreciation expense, property taxes, and operation and maintenance expenses related to Company-owned renewable energy project costs and capacity-related renewable energy purchased power costs not currently being recovered in base rates or eligible for recovery through the Fuel Cost Rider (FCR). Eligible projects (or portions of these projects) must be located in the state of North Dakota and must have previously been granted an Advance Determination of Prudence (ADP) by the Commission.

This application proposes a revised RER rate to recover the 2017 revenue requirements of RER approved projects that are not currently included in base rates.

In support of our request, we include details of the following:

- The 2015 and 2016 RER tracker account activity with true-ups for actual costs incurred and revenues collected, included in Attachment C and D, respectively;
- The projected RER tracker account activity for 2017, including both revenue requirements and projected revenues, included in Attachment E;
- The projected 2017 revenue requirements of \$2,026,203, proposed to be recovered through the RER Rate Rider from North Dakota electric customers; and

² Ottertail Power Company Renewable Generation Rider.

- The RER Rate of \$0.000898 per kWh for all customer classes shown in Attachment A.

III. PROJECT ELIGIBILITY

To be eligible for inclusion in the RER, a project must be a renewable energy resource, be located (all or in part) in the state of North Dakota, and have been granted an ADP by the Commission. The Border Winds and Courtenay wind projects are qualifying wind energy facilities located in the state of North Dakota that have each been granted an ADP by the Commission, but are not yet included in base rates. Both projects, therefore, meet the requirements established by the legislature and the Commission for inclusion in the RER. Each project is described more completely below. We propose to continue to include the projected revenue requirements associated with these two wind projects in the RER rate effective January 1, 2017. The following two projects were approved for recovery in our first RER proceeding, PU-15-683.

A. Border Winds

The Border Winds facility is a 150 MW wind resource developed by RES Americas in Rollette County, in northeastern North Dakota, which upon completion was transferred to the Company to own and operate in December 2015. The facility consists of 75 Vestas 2.0 MW wind turbine generators. Associated infrastructure includes access roads, electrical collection system, meteorological monitoring stations, a project collector substation, a new interconnection substation, and an operations and maintenance facility. The Company originally identified this project for acquisition through a competitive bidding process in which a Request for Proposals (RFP) for additional wind resources was issued in February 2013. On August 13, 2013, the Company filed an ADP Application seeking Commission approval to develop, own, and operate the Border Winds project. In Case No. PU-13-742, the Commission approved the ADP by Order dated February 26, 2014. The Border Winds facility officially went into service in December 2015.

B. Courtenay

The Courtenay wind project will be a 200 MW wind resource in Stutsman County, North Dakota that will cover 24,900 acres of land and, consistent with the Certificate of Site Compatibility, will consist of 100 Vestas 2.0 MW wind turbine generators and associated infrastructure. This project is also the result of our February 2013 RFP for additional wind resources. NSP was originally granted an ADP for the Courtenay project as a power purchase agreement in Case No. PU-13-706. However, due to changed circumstances, on April 30, 2015, the Company filed an ADP Application

seeking Commission approval to finish developing, own, and operate the Courtenay facility. In Case No. PU-15-181, the Commission approved the ADP by Order dated August 26, 2015.

Construction of Courtenay is currently in process with the project expected to be in-service in December 2016 and thus eligible for federal Production Tax Credits (PTCs).

IV. ALLOCATIONS, RATE DESIGN, AND ACCOUNTING

A. 2017 RER Revenue Requirements

The detailed investments, related revenue requirements, and other inputs and calculations in support of the proposed RER Rate are shown in the following attachments:

Attachment A	RER Rate Calculation
Attachment B	Annual Tracker Summary
Attachment C	2015 Tracker
Attachment D	2016 Tracker
Attachment E	2017 Tracker
Attachment F	2018 Tracker
Attachment G	Capital Expenditures
Attachment H	Monthly Revenue Requirement by Project
Attachment I	Production Tax Credits (PTCs)
Attachment J	Operation & Maintenance Expense (O&M)
Attachment K	Monthly Sales
Attachment L	Universal Inputs
Attachment M	Revised Tariff Sheet No. 87

B. Jurisdictional Energy and Demand Allocators

The revenue requirements included in the RER tracker are only those related to North Dakota's share of the Border Winds and Courtenay energy facilities and their associated costs. Northern States Power Company-Minnesota (NSPM) and Northern States Power Company-Wisconsin (NSPW) together the NSP Companies, operate as an integrated electric system (NSP System). The NSP Companies plan and operate the NSP System through the Federal Energy Regulatory Commission (FERC) approved Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy between NSPM and NSPW (Interchange Agreement). The Interchange Agreement is a formula rate which provides for charges to flow between NSPM and NSPW for certain electric production and transmission costs related to the NSP Companies' integrated electric system.

The Interchange Agreement provides for a sharing of NSP System production and transmission costs on a load ratio share basis in light of the integrated nature of the NSP System, and the charges between NSPM and NSPW are intended to accomplish such sharing. Under the terms of the Interchange Agreement tariff, all fixed production and all transmission costs are shared between the NSP Companies based on the respective Company's load ratio share (using a 36-month coincident peak demand allocator). All variable production costs are shared between the NSP Companies based on energy. As a result, approximately 84 percent of all production and transmission costs incurred by both NSPM and NSPW support customers of NSPM while approximately 16 percent support NSPW customers.

NSPM provides service to customers in North Dakota, South Dakota, and Minnesota. In general, NSPM's fixed production and all transmission costs (again, approximately 84 percent of total NSP System costs) are allocated to these three state jurisdictions based on load ratio share (using the 12-month coincident peak jurisdictional demand allocator approved by all three state commissions). Again, all variable production costs are shared between the NSPM jurisdictions based on energy including wind production investments, which are considered variable.

Based on these demand and energy allocators, approximately 6.5 percent of NSPM's production and transmission costs are allocated to the North Dakota jurisdiction. On a NSP System basis, approximately 5.5 percent (i.e. 84 percent multiplied by 6.5 percent) of total costs support the North Dakota jurisdiction.

The 2017 forecast revenue requirements are allocated to the North Dakota jurisdiction based on the 2017 jurisdictional demand and energy allocators, respectively. The sales and demand data used to calculate the jurisdictional allocators are consistent with the period's sales, which is also used to estimate the period's

customer collections. Total revenue requirements were allocated consistent with the process described above which serves to:

- Allocate a share of the total costs to NSPW; and
- Exclude the portion of NSPM costs not related to serving North Dakota retail customers. This step allocates a share of costs to the South Dakota and Minnesota retail jurisdictions, as well as the firm requirements wholesale customers base.³

Any resulting over- or under-recovery from customers that occurs in 2017 as a result of the use of forecast data will be trued-up to actual jurisdictional revenue requirements at the time the 2018 RER rate is determined.

Table 1 below shows the cost category, allocation method, and allocator used to assign 2017 forecasted costs to the North Dakota jurisdiction. The derivation of the individual allocators is shown in Attachment L.

Table 1: 2017 RER Allocators

Cost Category	Allocation Method	2017 ND Allocator
Wind Investment-related costs; Property Taxes	Composite Energy & Demand	5.4870%
Transmission-related costs; Production O&M - Fixed	Composite Demand	5.2525%
PTCs; Production O&M - Variable	Composite Energy	5.4707%

By performing this cost allocation process, we ensure that electric customers in other jurisdictions are allocated a share of the Border Winds and Courtenay revenue requirements, consistent with the Company’s allocation of similar costs in a general rate case.

C. Taxes

The RER rate includes current and deferred taxes, and also property taxes on both the wind and transmission facilities. In addition, the revenue requirements are off-set by PTCs, North Dakota Investment Tax Credits (NDITCs), and Accumulated Deferred Income Taxes (ADIT) as further described below.

³ NSPM currently does not have any full requirements wholesale customers on the NSP system.

1. Property Tax

a. Wind Facilities

The tax in lieu of property taxes for the wind facilities is calculated based on a formula with two parts: one based on nameplate capacity and one based on energy production. We have applied the formula specific to the capacity and estimated wind generation for the Border Winds and Courtenay projects and include the results in our revenue requirements calculations.

b. Transmission Facilities

The property tax associated with the transmission facilities is calculated using a method consistent with that used in our Transmission Cost Recovery (TCR) Rider. The North Dakota state composite property tax rate is applied to the gross transmission plant in service at the end of the prior year. The North Dakota composite rate is calculated by the Company's Tax Department and reflects the ratio of 2016 payable property taxes to North Dakota taxable investment as valued at the end of the prior year.

2. Revenue Requirements Offsets

a. PTCs

The Border Winds facility is currently eligible for the federal PTC and the Courtenay project will be eligible when it goes in-service and is producing energy. PTC benefits are based on actual and expected energy production. We have calculated the PTCs on a monthly basis and used the credit amount to offset the revenue requirement. PTCs are calculated by multiplying the actual or expected kWh generated by the currently effective per kWh credit. The 2016 PTC credit is 2.3 cents per kWh. In this filing, we assumed the 2016 rate going forward; however, we would update the credit for future years if the Internal Revenue Service (IRS) makes changes to the law that would redefine the credit. The actual PTC benefits will be trueed up through the RER Tracker Account and updated in each annual filing.

Note that due to the variability of wind production, we propose to continue to true-up the PTC for the Border Winds and Courtenay projects in future RER tracker updates, even after the project costs have been incorporated into base rates.

b. North Dakota Investment Tax Credits

N.D.C.C. Section 57-38-01.8 provides for a tax credit against North Dakota income taxes for the installation of solar, biomass, geothermal, and wind projects that meet certain requirements. Because this tax credit is structured to provide a credit against North Dakota income taxes, an entity must have sufficient North Dakota income tax liability to realize the benefits.

In the 2016 RER filing, the Company expected to have a North Dakota tax liability, and therefore offsetting ND ITCs in 2016 and 2017. However, due to the extension of bonus depreciation in the 2015 Protecting Americans from Tax Hikes (PATH) Act, the Company no longer expects a North Dakota tax liability to have a ND ITC offset.

c. Accumulated Deferred Income Taxes

The Company continues to calculate the plant related Accumulated Deferred Income Taxes (ADIT) offset to rate base in accordance with the proration formula in IRS regulation section 1.167(1)-1(h)(6). The December 1, 2015 supplemental filing for the 2016 RER addressed the revenue requirement impact of the ADIT proration formula.

D. Capital Structure

The Company has calculated the revenue requirements consistent with the approved *Revised Second Amended Settlement* in Case No. PU-12-813. The capital structure approved in that docket was included on Attachment D of the Settlement Agreement. (See Attachment L)

E. Depreciation

The remaining life assumptions used in this filing are consistent with the remaining lives approved in the last North Dakota electric rate case. The Company is proposing a depreciable life assumption of 25 years for both of these wind projects as that is the standard depreciation the Company assigns to all wind assets. If any changes are made to the projects' remaining lives in future Commission Orders, those changes will be reflected in future filings.

F. Operation and Maintenance Expense

As allowed under the enabling statute, the proposed RER rate includes projected O&M expense for Company labor and related labor costs, consulting services and other outside contract vendor costs, routine janitorial, electric and gas service, sewer maintenance, snow removal, landowner payments, space costs and avian costs. We believe these expenses are reasonable and will be necessary to operate and maintain these two wind production facilities.

G. Transmission Costs

We include in the overall revenue requirement calculation of the budgeted amount of payment to Otter Tail Power Company and Minnkota Power Cooperative which are required to interconnect the Courtenay project to the transmission system.

H. RER Tracker Account

To ensure that customers are not under or overcharged, we will record the actual RER revenues and costs in a tracker account as the accounting mechanism for eligible RER facilities costs. Any differences based on the estimated end-of-year balance in the tracker account will be returned or collected as part of our next annual RER Rate application.

Each month as revenues are collected from retail customers, the Company will track the amount of recovery under the RER rate and will compare that amount with the actual monthly revenue requirement (costs). The difference will be recorded in the tracker account as the amount of over- or under-recovery. Any over- or under-recovery balance at the end of the year is used in the calculation of the RER rate for the following year.

I. Accounting for the Tracker

Xcel Energy calculates the monthly North Dakota jurisdictional revenue requirements (including appropriate overall return, income taxes, property taxes and depreciation), and compares them with monthly RER rate recoveries from customers. The under-recovered amounts are recorded in FERC Account 182.3, Other Regulatory Assets and the over-recovered amounts are recorded in FERC Account 254, Other Regulatory Liabilities (the Tracker Accounts).

V. RATE APPLICATION AND IMPACT

A. Updated RER Rate

The Company's RER rate design represents the total annual calculated revenue requirement for 2017 divided by the forecasted energy sales to North Dakota electric retail customers during the 2017 calendar year. The rate is rounded to the nearest \$0.000001 per kWh. This calculation is shown on Attachment A. Based on this rate design, we propose the following RER Rate:

Table 2: 2017 RER Rate Calculation

	Retail
ND Retail Revenue Requirements <i>2017</i>	\$2,026,203
ND Retail Sales (kWh) <i>Jan.-Dec. 2017</i>	2,255,536,676
2017 RER Rate Cost Per kWh	\$0.000898

The average bill impact for a residential customer using 750 kWh in a month would be \$0.67 per month, or about \$0.03 less than the impact of the current monthly RER rate.

For each 12-month period ending December 31, a true-up adjustment will be recorded to reset the Tracker Account. The true-up will reflect the difference between the collected RER revenues and the actual RER revenue requirement for the period.

B. Tariff

Xcel Energy proposes to update its Renewable Energy Rider tariff sheet number 87 in Section 5 of the North Dakota Electric Rate Book–NDPSC No. 2 with the proposed 2017 rate. Attachment M depicts the proposed tariff sheet.

The tariff provides that the RER rate will be applied to customer bills subsequent to Commission approval. While we propose an effective date of January 1, 2017, the tariff sheet and revised RER rate will not be effective until the Commission approves this application.

The RER tariff sheet will be updated to comply with the Commission’s final order in this proceeding. If the final RER rate goes into effect after January 1, 2017, or the Commission determines modifications need to be made to the level of revenues we have proposed for RER recovery, the Company will calculate the final RER rate based on the approved revenue requirement and forecasted sales over the remaining months of 2017. Our 2018 RER rate application will be filed in late 2017.

C. Notice to Customers

The Company will provide notice to customers regarding the new RER rate reflected in their monthly electric bill. We propose the following language be included as a notice on customer bills during the month the RER rate is implemented:

On Nov. 1, 2016, Xcel Energy filed a request with the North Dakota Public Service Commission to decrease the Renewable Energy Rider (RER) rate from \$0.000936 to \$0.000898 per kWh. If approved, you can expect an average monthly bill decrease of about \$0.03. The proposed rate change is for bills beginning Jan. 1, 2017, and will not be effective until approved by the Commission.

Four separate customer class notices will be developed and issued to residential (non-space heating), residential space heating, small commercial, and large commercial customers, respectively, to ensure compliance with the customer information provisions of ND Admin. Rule 69-09-02-02.1. We will work with Commission Staff to incorporate their feedback on the proposed customer notice.

APPEARANCE OF COUNSEL

The Company will be represented in this proceeding by the following counsel upon whom all pleadings, documents and other filings should be served:

Alison Archer
Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401-8th Floor
Minneapolis, MN 55401
Alison.C.Archer@xcelenergy.com

We request that all communications regarding this proceeding, including data requests, also be directed to:

Carl Cronin
Regulatory Administrator
Xcel Energy Services Inc.
414 Nicollet Mall, 401-7th floor
Minneapolis, MN 55401
Regulatory.Records@xcelenergy.com

CONCLUSION

Xcel Energy respectfully requests that the Commission approve the proposed RER rate for 2017 as described in this filing. This rate is designed to recover the costs associated with significant investments in renewable energy facilities that are not presently reflected in our general rate schedules.

Dated: November 1, 2016

Northern States Power Company

RER Rate - 2017		<i>Reference</i>
2017 Revenue Requirements	\$2,026,203	<i>Att. E</i>
Forecasted kWh Sales	2,255,536,676	<i>Att. K</i>
RER Cost per kWh	\$0.000898	

Northern States Power Company
 State of North Dakota
 Renewable Energy Rider (RER)

Case No. PU-16-____
 Application
 Attachment B
 1 of 1

Annual Tracker Summary					
	2015	2016	2017	2018	
	<i>Att. C</i>	<i>Att. D</i>	<i>Att. E</i>	<i>Att. F</i>	<u>Reference</u>
Carryover Balance	-	267,616	(325,259)	(0)	
Border Winds Capital *	303,240	1,870,817	1,687,490	1,561,538	<i>Att. H</i>
PTCs	(63,635)	(1,161,437)	(1,078,858)	(1,078,858)	<i>Att. I</i>
O&M	28,011	272,171	279,405	267,193	<i>Att. J</i>
Property Taxes	-	33,430	33,236	33,236	
Total Border Winds Costs	267,616	1,014,981	921,273	783,109	
Courtenay Wind Capital *	-	492,008	2,166,831	1,970,439	<i>Att. H</i>
PTCs	-	(79,746)	(1,290,214)	(1,372,540)	<i>Att. I</i>
O&M	-	70,867	379,611	396,938	<i>Att. J</i>
Transmission (Interconnect) Costs	-	14,278	118,053	114,828	
Property Taxes	-	-	55,908	55,908	
Total Courtenay Wind Costs	-	497,407	1,430,189	1,165,573	
Revenue Requirement	267,616	1,780,004	2,026,203	1,948,682	
Revenue Collections	-	2,105,263	2,026,203	1,948,682	
Balance	267,616	(325,259)	(0)	(0)	

2015 Tracker															Reference	
Carryover	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Annual Total			
	Actual*	Actual*	Actual*	Actual*	Actual*	Actual*	Actual*	Actual*	Actual*	Actual*	Actual*	Actual*				
Carryover Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Border Winds Capital		29,634	26,809	24,644	22,489	20,369	17,842	15,302	12,994	10,795	8,479	6,131	107,750	303,240	Att. H	
PTCs		-	-	-	-	-	-	-	-	-	-	-	(63,635)	(63,635)	Att. I	
O&M		2,334	2,334	2,334	2,334	2,334	2,334	2,334	2,334	2,334	2,334	2,334	2,335	28,011	Att. J	
Property Taxes		-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Border Winds Costs		31,968	29,143	26,978	24,823	22,703	20,176	17,636	15,328	13,129	10,813	8,466	46,450	267,616		
Courtenay Wind Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	Att. H
PTCs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	Att. I
O&M		-	-	-	-	-	-	-	-	-	-	-	-	-	-	Att. J
Transmission (Interconnect) Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Property Taxes		-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Courtenay Wind Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Revenue Requirement		31,968	29,143	26,978	24,823	22,703	20,176	17,636	15,328	13,129	10,813	8,466	46,450	267,616		
Revenue Collections		-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Balance		31,968	61,112	88,090	112,913	135,616	155,792	173,429	188,757	201,886	212,700	221,165	267,616			

* Note - The "Actual" label refers to data inputs into the revenue requirement calculation, for example PTCs, O&M expenditures, and Plant In-Service balances based on capital expenditures. However, the total revenue requirements is subject to change at year-end due to updating forecast to actuals, allocator updates, and annual deferred tax calculations.

2016 Tracker															Reference
Carryover	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Annual Total		
	Actual*	Actual*	Actual*	Actual*	Actual*	Actual*	Actual*	Actual*	Mixed	Forecast	Forecast	Forecast			
Carryover Balance	267,616	22,301	22,301	22,301	22,301	22,301	22,301	22,301	22,301	22,301	22,301	22,301	22,301	267,616	
Border Winds Capital		159,577	158,594	159,781	158,749	157,741	156,368	155,502	154,994	153,957	152,904	151,851	150,798	1,870,817	Att. H
PTCs		(96,786)	(96,786)	(96,786)	(96,786)	(96,786)	(96,786)	(96,786)	(96,786)	(96,786)	(96,786)	(96,786)	(96,786)	(1,161,437)	Att. I
O&M		22,681	22,681	22,681	22,681	22,681	22,681	22,681	22,681	22,681	22,681	22,681	22,681	272,171	Att. J
Property Taxes		2,786	2,786	2,786	2,786	2,786	2,786	2,786	2,786	2,786	2,786	2,786	2,786	33,430	
Total Border Winds Costs		88,258	87,274	88,462	87,430	86,422	85,049	84,182	83,674	82,638	81,584	80,531	79,478	1,014,981	
Courtenay Wind Capital		39,138	36,479	33,827	31,203	30,201	31,616	32,532	31,447	30,532	29,882	28,674	136,476	492,008	Att. H
PTCs		-	-	-	-	-	-	-	-	-	-	-	(79,746)	(79,746)	Att. I
O&M		5,906	5,906	5,906	5,906	5,906	5,906	5,906	5,906	5,906	5,906	5,906	5,906	70,867	Att. J
Transmission (Interconnect) Costs		-	-	-	-	-	-	-	-	-	-	4,759	9,519	14,278	
Property Taxes		-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Courtenay Wind Costs		45,043	42,385	39,732	37,109	36,107	37,522	38,438	37,353	36,438	35,788	39,339	72,154	497,407	
Revenue Requirement		155,602	151,960	150,495	146,840	144,830	144,872	144,921	143,328	141,377	139,673	142,172	173,933	1,780,004	
Revenue Collections		221,001	173,391	173,958	142,215	159,181	167,179	180,518	186,945	157,489	160,362	179,779	203,245	2,105,263	
Balance		(65,399)	(86,830)	(110,293)	(105,668)	(120,019)	(142,326)	(177,922)	(221,539)	(237,651)	(258,340)	(295,947)	(325,259)		

* Note - The "Actual" label refers to data inputs into the revenue requirement calculation, for example PTCs, O&M expenditures, and Plant In-Service balances based on capital expenditures. However, the total revenue requirements is subject to change at year-end due to updating forecast to actuals, allocator updates, and annual deferred tax calculations.

2017 Tracker															Annual Total	Reference
Carryover	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17				
	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast			
Carryover Balance	(325,259)	(27,105)	(27,105)	(27,105)	(27,105)	(27,105)	(27,105)	(27,105)	(27,105)	(27,105)	(27,105)	(27,105)	(27,105)	(27,105)	(325,259)	
Border Winds Capital		144,783	144,027	143,271	142,514	141,758	141,002	140,246	139,490	138,734	137,978	137,222	136,465		1,687,490	Att. H
PTCs		(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)		(1,078,858)	Att. I
O&M		23,284	23,284	23,284	23,284	23,284	23,284	23,284	23,284	23,284	23,284	23,284	23,284		279,405	Att. J
Property Taxes		2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770		33,236	
Total Border Winds Costs		80,932	80,175	79,419	78,663	77,907	77,151	76,395	75,639	74,882	74,126	73,370	72,614		921,273	
Courtenay Wind Capital		186,885	185,746	184,599	183,450	182,298	181,147	179,996	178,845	177,693	176,542	175,391	174,240		2,166,831	Att. H
PTCs		(107,518)	(107,518)	(107,518)	(107,518)	(107,518)	(107,518)	(107,518)	(107,518)	(107,518)	(107,518)	(107,518)	(107,518)		(1,290,214)	Att. I
O&M		31,634	31,634	31,634	31,634	31,634	31,634	31,634	31,634	31,634	31,634	31,634	31,634		379,611	Att. J
Transmission (Interconnect) Costs		9,838	9,838	9,838	9,838	9,838	9,838	9,838	9,838	9,838	9,838	9,838	9,838		118,053	
Property Taxes		4,659	4,659	4,659	4,659	4,659	4,659	4,659	4,659	4,659	4,659	4,659	4,659		55,908	
Total Courtenay Wind Costs		125,498	124,359	123,212	122,063	120,911	119,760	118,609	117,458	116,307	115,155	114,004	112,853		1,430,189	
Revenue Requirement		179,325	177,429	175,526	173,621	171,714	169,806	167,899	165,991	164,084	162,177	160,269	158,362		2,026,203	Att. A
Revenue Collections		204,433	172,663	178,612	143,705	150,320	154,769	175,351	170,366	152,701	154,046	173,069	196,169		2,026,203	Att. K
Balance		(25,108)	(20,342)	(23,427)	6,488	27,881	42,918	35,466	31,092	42,475	50,606	37,806	(0)			

2018 Tracker															Annual Total	Reference	
Carryover	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18					
	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast				
Carryover Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)		
Border Winds Capital	133,340	132,756	132,172	131,588	131,004	130,420	129,836	129,252	128,668	128,084	127,500	126,916	126,332	125,748	125,160	1,561,538	Att. H
PTCs	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(89,905)	(1,078,858)	Att. I
O&M	22,266	22,266	22,266	22,266	22,266	22,266	22,266	22,266	22,266	22,266	22,266	22,266	22,266	22,266	22,266	267,193	Att. J
Property Taxes	2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770	2,770	33,236		
Total Border Winds Costs	68,471	67,887	67,303	66,719	66,135	65,551	64,967	64,383	63,799	63,215	62,631	62,047	61,463	60,879	60,295	783,109	
Courtenay Wind Capital	168,835	167,993	167,151	166,309	165,466	164,624	163,782	162,940	162,098	161,256	160,413	159,571	158,729	157,887	157,045	1,970,439	Att. H
PTCs	(114,378)	(114,378)	(114,378)	(114,378)	(114,378)	(114,378)	(114,378)	(114,378)	(114,378)	(114,378)	(114,378)	(114,378)	(114,378)	(114,378)	(114,378)	(1,372,540)	Att. I
O&M	33,078	33,078	33,078	33,078	33,078	33,078	33,078	33,078	33,078	33,078	33,078	33,078	33,078	33,078	33,078	396,938	Att. J
Transmission (Interconnect) Costs	9,569	9,569	9,569	9,569	9,569	9,569	9,569	9,569	9,569	9,569	9,569	9,569	9,569	9,569	114,828		
Property Taxes	4,659	4,659	4,659	4,659	4,659	4,659	4,659	4,659	4,659	4,659	4,659	4,659	4,659	4,659	55,908		
Total Courtenay Wind Costs	101,763	100,921	100,079	99,236	98,394	97,552	96,710	95,868	95,026	94,183	93,341	92,499	91,657	90,815	90,000	1,165,573	
Revenue Requirement	170,234	168,808	167,382	165,955	164,529	163,103	161,677	160,251	158,825	157,399	155,973	154,547	153,121	151,695	150,269	1,948,682	
Revenue Collections	197,692	165,714	171,491	139,741	143,516	148,249	168,769	163,702	146,280	148,384	166,359	188,784				1,948,682	
Balance	(27,458)	(24,365)	(28,474)	(2,259)	18,754	33,608	26,516	23,065	35,610	44,624	34,238	(0)					

Capital Expenditures						
	2013	2014	2015	2016	2017	Total
<u>Border Winds</u>						
Production	9,339	15,776,317	244,383,320	742,406		260,911,382
Trans Serving Generation		56,959	36,258			93,217
Total Border Winds - Capital Expenditures	9,339	15,833,276	244,419,578	742,406		261,004,599
<u>Courtenay Wind</u>						
Production			95,104,509	180,130,353	35,000	275,269,862
Trans Serving Generation			739,039	5,775,365		6,514,404
Transmission			285,755	7,293,006		7,578,761
Land Rights			750,748	2,386,224		3,136,972
Total Courtenay Wind - Capital Expenditures			96,880,051	195,584,948	35,000	292,499,999

	2015 Capital Revenue Requirement by Project												Total
	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	
Border Winds													
Rate Base													
Plant In-Service	-	-	-	-	-	-	-	-	-	-	-	261,855,550	261,855,550
Less Accumulated Book Depreciation Reserve	-	-	-	-	-	-	-	-	-	-	-	457,925	457,925
Less Accumulated Deferred Taxes	4,739,936	9,538,646	14,337,355	19,136,065	23,934,775	28,733,485	33,532,195	38,330,904	43,129,614	47,928,324	52,727,034	57,525,744	57,525,744
End Of Month Rate Base	(4,739,936)	(9,538,646)	(14,337,355)	(19,136,065)	(23,934,775)	(28,733,485)	(33,532,195)	(38,330,904)	(43,129,614)	(47,928,324)	(52,727,034)	203,871,882	203,871,882
Return on Rate Base													
Debt Return	(4,545)	(13,862)	(23,180)	(32,497)	(41,815)	(51,132)	(60,450)	(69,767)	(79,085)	(88,402)	(97,720)	146,736	(415,717)
Equity Return	(10,260)	(31,294)	(52,328)	(73,363)	(94,397)	(115,431)	(136,466)	(157,500)	(178,534)	(199,569)	(220,603)	331,259	(938,485)
Total Return on Rate Base	(14,804)	(45,156)	(75,508)	(105,860)	(136,212)	(166,563)	(196,915)	(227,267)	(257,619)	(287,971)	(318,323)	477,996	(1,354,202)
Income Statement Items													
Book Depreciation	-	-	-	-	-	-	-	-	-	-	-	457,925	457,925
Deferred Taxes	4,798,710	4,798,710	4,798,710	4,798,710	4,798,710	4,798,710	4,798,710	4,798,710	4,798,710	4,798,710	4,798,710	4,798,710	57,584,518
Gross Up for Income Tax	(4,242,916)	(4,264,131)	(4,273,304)	(4,282,291)	(4,290,654)	(4,306,423)	(4,322,441)	(4,334,223)	(4,344,017)	(4,355,945)	(4,368,453)	(3,767,567)	(51,152,363)
Total Income Statement Expense	555,794	534,579	525,405	516,419	508,056	492,287	476,269	464,487	454,693	442,765	430,257	1,489,068	6,890,079
Total Revenue Requirement	540,989	489,423	449,898	410,559	371,845	325,724	279,354	237,220	197,074	154,794	111,935	1,967,063	5,535,878
Rider Eligible Revenue Requirement	29,634	26,809	24,644	22,489	20,369	17,842	15,302	12,994	10,795	8,479	6,131	107,750	303,240
ADIT Prorate Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Rider Eligible Revenue Requirement	29,634	26,809	24,644	22,489	20,369	17,842	15,302	12,994	10,795	8,479	6,131	107,750	303,240
Courtenay Wind													
Rate Base													
Plant In-Service	-	-	-	-	-	-	-	-	-	-	-	-	-
Less Accumulated Book Depreciation Reserve	-	-	-	-	-	-	-	-	-	-	-	-	-
Less Accumulated Deferred Taxes	(11,923)	(23,846)	(35,768)	(47,691)	(59,614)	(71,537)	(83,460)	(95,382)	(107,305)	(119,228)	(131,151)	(143,074)	(143,074)
End Of Month Rate Base	11,923	23,846	35,768	47,691	59,614	71,537	83,460	95,382	107,305	119,228	131,151	143,074	143,074
Return on Rate Base													
Debt Return	12	35	58	81	104	127	150	174	197	220	243	266	1,667
Equity Return	26	78	131	183	235	287	340	392	444	496	549	601	3,763
Total Return on Rate Base	38	113	189	264	339	415	490	566	641	716	792	867	5,430
Income Statement Items													
Book Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes	(11,923)	(11,923)	(11,923)	(11,923)	(11,923)	(11,923)	(11,923)	(11,923)	(11,923)	(11,923)	(11,923)	(11,923)	(143,074)
Gross Up for Income Tax	(7,230)	(7,199)	(7,167)	(2,218)	4,478	3,885	3,198	4,685	48,928	99,778	114,223	147,529	402,890
Total Income Statement Expense	(19,153)	(19,121)	(19,090)	(14,140)	(7,445)	(8,038)	(8,725)	(7,238)	37,005	87,855	102,300	135,606	259,816
Total Revenue Requirement	(19,115)	(19,008)	(18,901)	(13,877)	(7,106)	(7,623)	(8,235)	(6,672)	37,646	88,572	103,092	136,473	265,246
Rider Eligible Revenue Requirement	-	-	-	-	-	-	-	-	-	-	-	-	-
ADIT Prorate Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Rider Eligible Revenue Requirement	-	-	-	-	-	-	-	-	-	-	-	-	-

Reference

Att. C

Att. C

Note: Rider Eligible Requirements are calculated using both Energy and Demand allocators from the separate Production and Transmission components of the project

	2016 Capital Revenue Requirement by Project												Total
	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	
Border Winds													
Rate Base													
Plant In-Service	256,476,984	261,922,758	261,939,966	261,953,382	262,005,191	261,168,608	262,602,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158
Less Accumulated Book Depreciation Reserve	1,365,872	2,273,937	3,191,654	4,109,426	5,027,314	5,943,801	6,861,357	7,781,562	8,701,839	9,622,116	10,542,392	11,462,669	11,462,669
Less Accumulated Deferred Taxes	58,688,110	59,850,477	61,012,844	62,175,211	63,337,578	64,499,945	65,662,312	66,824,679	67,987,046	69,149,412	70,311,779	71,474,146	71,474,146
End Of Month Rate Base	196,423,002	199,798,344	197,735,467	195,668,745	193,640,299	190,724,862	190,078,489	188,035,917	185,953,274	183,870,630	181,787,986	179,705,343	179,705,343
Return on Rate Base													
Debt Return	388,620	384,665	385,939	381,930	377,954	373,155	369,697	367,086	363,081	359,037	354,994	350,950	350,950
Equity Return	898,996	889,847	892,795	883,520	874,323	863,220	855,221	849,182	839,917	830,563	821,208	811,854	811,854
Total Return on Rate Base	1,287,615	1,274,512	1,278,734	1,265,450	1,252,277	1,236,375	1,224,917	1,216,268	1,202,999	1,189,600	1,176,202	1,162,804	1,162,804
Income Statement Items													
Book Depreciation	907,947	908,065	917,718	917,772	917,888	916,487	917,556	920,205	920,277	920,277	920,277	920,277	920,277
Deferred Taxes	1,162,367	1,162,367	1,162,367	1,162,367	1,162,367	1,162,367	1,162,367	1,162,367	1,162,367	1,162,367	1,162,367	1,162,367	1,162,367
Gross Up for Income Tax	(481,110)	(485,949)	(478,303)	(483,772)	(488,977)	(496,553)	(501,863)	(505,065)	(510,651)	(516,337)	(522,022)	(527,707)	(527,707)
Total Income Statement Expense	1,589,203	1,584,483	1,601,782	1,596,367	1,591,278	1,582,301	1,578,060	1,577,507	1,571,992	1,566,307	1,560,622	1,554,936	1,554,936
Total Revenue Requirement	2,876,819	2,858,995	2,880,515	2,861,817	2,843,555	2,818,675	2,802,977	2,793,775	2,774,991	2,755,907	2,736,824	2,717,740	2,717,740
Rider Eligible Revenue Requirement	158,769	157,785	158,973	157,941	156,933	155,560	154,694	154,186	153,149	152,096	151,043	149,989	149,989
ADIT Prorate Adjustment	808	808	808	808	808	808	808	808	808	808	808	808	808
Total Rider Eligible Revenue Requirement	159,577	158,594	159,781	158,749	157,741	156,368	155,502	154,994	153,957	152,904	151,851	150,798	150,798
Courtenay Wind													
Rate Base													
Plant In-Service	-	-	-	-	-	-	-	-	-	-	-	-	305,309,482
Less Accumulated Book Depreciation Reserve	-	-	-	-	-	-	-	-	-	-	-	-	515,145
Less Accumulated Deferred Taxes	5,196,147	10,535,367	15,874,588	21,213,808	26,553,029	31,892,249	37,231,470	42,570,690	47,909,911	53,249,131	58,588,352	63,927,572	63,927,572
End Of Month Rate Base	(5,196,147)	(10,535,367)	(15,874,588)	(21,213,808)	(26,553,029)	(31,892,249)	(37,231,470)	(42,570,690)	(47,909,911)	(53,249,131)	(58,588,352)	(63,927,572)	240,866,764
Return on Rate Base													
Debt Return	(4,906)	(15,273)	(25,640)	(36,007)	(46,374)	(56,741)	(67,108)	(77,475)	(87,842)	(98,209)	(108,576)	176,962	(447,185)
Equity Return	(11,348)	(35,330)	(59,312)	(83,294)	(107,276)	(131,258)	(155,240)	(179,222)	(203,204)	(227,186)	(251,168)	409,367	(1,034,475)
Total Return on Rate Base	(16,254)	(50,603)	(84,952)	(119,301)	(153,650)	(187,999)	(222,348)	(256,697)	(291,046)	(325,395)	(359,744)	586,329	(1,481,660)
Income Statement Items													
Book Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	515,145
Deferred Taxes	5,339,220	5,339,220	5,339,220	5,339,220	5,339,220	5,339,220	5,339,220	5,339,220	5,339,220	5,339,220	5,339,220	5,339,220	5,339,220
Gross Up for Income Tax	(4,679,841)	(4,693,771)	(4,707,593)	(4,720,862)	(4,704,721)	(4,644,641)	(4,593,360)	(4,578,436)	(4,560,691)	(4,538,233)	(4,525,870)	(4,030,122)	(54,978,143)
Total Income Statement Expense	659,380	645,449	631,628	618,358	634,499	694,579	745,860	760,785	778,529	800,988	813,350	1,824,244	9,607,649
Total Revenue Requirement	643,125	594,846	546,676	499,057	480,849	506,580	523,512	504,088	487,483	475,593	453,606	2,410,573	8,125,989
Rider Eligible Revenue Requirement	35,428	32,769	30,117	27,493	26,491	27,906	28,822	27,737	26,822	26,172	24,964	132,766	447,488
ADIT Prorate Adjustment	3,710	3,710	3,710	3,710	3,710	3,710	3,710	3,710	3,710	3,710	3,710	3,710	44,520
Total Rider Eligible Revenue Requirement	39,138	36,479	33,827	31,203	30,201	31,616	32,532	31,447	30,532	29,882	28,674	136,476	492,008

Reference

Att. D

Att. D

Note: Rider Eligible Requirements are calculated using both Energy and Demand allocators from the separate Production and Transmission components of the project

	2017 Capital Revenue Requirement by Project												Total
	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	
Border Winds													
Rate Base													
Plant In-Service	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158
Less Accumulated Book Depreciation Reserve	12,382,946	13,303,223	14,223,500	15,143,776	16,064,053	16,984,330	17,904,607	18,824,884	19,745,160	20,665,437	21,585,714	22,505,991	22,505,991
Less Accumulated Deferred Taxes	72,057,797	72,641,447	73,225,097	73,808,748	74,392,398	74,976,049	75,559,699	76,143,349	76,727,000	77,310,650	77,894,301	78,477,951	78,477,951
End Of Month Rate Base	178,201,415	176,697,488	175,193,561	173,689,634	172,185,707	170,681,779	169,177,852	167,673,925	166,169,998	164,666,071	163,162,143	161,658,216	161,658,216
Return on Rate Base													
Debt Return	347,468	344,548	341,628	338,707	335,787	332,867	329,947	327,027	324,107	321,187	318,267	315,346	315,346
Equity Return	803,799	797,044	790,289	783,534	776,778	770,023	763,268	756,513	749,758	743,003	736,248	729,492	729,492
Total Return on Rate Base	1,151,267	1,141,591	1,131,916	1,122,241	1,112,566	1,102,890	1,093,215	1,083,540	1,073,865	1,064,189	1,054,514	1,044,839	1,044,839
Income Statement Items													
Book Depreciation	920,277	920,277	920,277	920,277	920,277	920,277	920,277	920,277	920,277	920,277	920,277	920,277	920,277
Deferred Taxes	583,650	583,650	583,650	583,650	583,650	583,650	583,650	583,650	583,650	583,650	583,650	583,650	583,650
Gross Up for Income Tax	(23,826)	(27,932)	(32,037)	(36,143)	(40,248)	(44,354)	(48,459)	(52,565)	(56,670)	(60,776)	(64,881)	(68,987)	(68,987)
Total Income Statement Expense	1,480,101	1,475,995	1,471,890	1,467,784	1,463,679	1,459,573	1,455,468	1,451,363	1,447,257	1,443,152	1,439,046	1,434,941	1,434,941
Total Revenue Requirement	2,631,368	2,617,587	2,603,806	2,590,025	2,576,245	2,562,464	2,548,683	2,534,902	2,521,122	2,507,341	2,493,560	2,479,779	2,479,779
Rider Eligible Revenue Requirement	144,380	143,624	142,868	142,111	141,355	140,599	139,843	139,087	138,331	137,575	136,818	136,062	136,062
ADIT Prorate Adjustment	403	403	403	403	403	403	403	403	403	403	403	403	403
Total Rider Eligible Revenue Requirement	144,783	144,027	143,271	142,514	141,758	141,002	140,246	139,490	138,734	137,978	137,222	136,465	136,465
Courtenay Wind													
Rate Base													
Plant In-Service	305,334,482	305,339,482	305,344,482	305,344,482	305,344,482	305,344,482	305,344,482	305,344,482	305,344,482	305,344,482	305,344,482	305,344,482	305,344,482
Less Accumulated Book Depreciation Reserve	1,547,163	2,579,233	3,611,320	4,643,417	5,675,513	6,707,609	7,739,706	8,771,802	9,803,898	10,835,995	11,868,091	12,900,187	12,900,187
Less Accumulated Deferred Taxes	65,186,937	66,446,302	67,705,667	68,965,033	70,224,398	71,483,763	72,743,128	74,002,493	75,261,858	76,521,223	77,780,588	79,039,953	79,039,953
End Of Month Rate Base	238,600,382	236,313,947	234,027,494	231,736,033	229,444,571	227,153,110	224,861,648	222,570,187	220,278,726	217,987,264	215,695,803	213,404,341	213,404,341
Return on Rate Base													
Debt Return	465,483	461,063	456,623	452,179	447,730	443,280	438,831	434,382	429,932	425,483	421,034	416,585	416,585
Equity Return	1,076,803	1,066,578	1,056,308	1,046,027	1,035,735	1,025,442	1,015,150	1,004,857	994,565	984,272	973,980	963,687	963,687
Total Return on Rate Base	1,542,286	1,527,641	1,512,932	1,498,206	1,483,464	1,468,723	1,453,981	1,439,239	1,424,497	1,409,756	1,395,014	1,380,272	1,380,272
Income Statement Items													
Book Depreciation	1,032,018	1,032,070	1,032,088	1,032,096	1,032,096	1,032,096	1,032,096	1,032,096	1,032,096	1,032,096	1,032,096	1,032,096	1,032,096
Deferred Taxes	1,259,365	1,259,365	1,259,365	1,259,365	1,259,365	1,259,365	1,259,365	1,259,365	1,259,365	1,259,365	1,259,365	1,259,365	1,259,365
Gross Up for Income Tax	(437,923)	(444,105)	(450,336)	(456,579)	(462,835)	(469,090)	(475,345)	(481,600)	(487,856)	(494,111)	(500,366)	(506,622)	(506,622)
Total Income Statement Expense	1,853,460	1,847,330	1,841,117	1,834,882	1,828,627	1,822,372	1,816,116	1,809,861	1,803,606	1,797,350	1,791,095	1,784,840	1,784,840
Total Revenue Requirement	3,395,746	3,374,971	3,354,048	3,333,088	3,312,091	3,291,094	3,270,097	3,249,100	3,228,103	3,207,106	3,186,109	3,165,112	3,165,112
Rider Eligible Revenue Requirement	186,015	184,876	183,728	182,579	181,428	180,277	179,126	177,974	176,823	175,672	174,521	173,369	173,369
ADIT Prorate Adjustment	870	870	870	870	870	870	870	870	870	870	870	870	870
Total Rider Eligible Revenue Requirement	186,885	185,746	184,599	183,450	182,298	181,147	179,996	178,845	177,693	176,542	175,391	174,240	174,240

Reference

Att. E

Att. E

Note: Rider Eligible Requirements are calculated using both Energy and Demand allocators from the separate Production and Transmission components of the project

	2018 Capital Revenue Requirement by Project												Total
	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	
Border Winds													
Rate Base													
Plant In-Service	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158	262,642,158
Less Accumulated Book Depreciation Reserve	23,426,268	24,346,544	25,266,821	26,187,098	27,107,375	28,027,651	28,947,928	29,868,205	30,788,482	31,708,759	32,629,035	33,549,312	33,549,312
Less Accumulated Deferred Taxes	78,719,136	78,960,320	79,201,505	79,442,690	79,683,875	79,925,059	80,166,244	80,407,429	80,648,614	80,889,798	81,130,983	81,372,168	81,372,168
End Of Month Rate Base	160,496,755	159,335,293	158,173,832	157,012,370	155,850,909	154,689,447	153,527,986	152,366,524	151,205,063	150,043,601	148,882,140	147,720,678	147,720,678
Return on Rate Base													
Debt Return	312,759	310,504	308,248	305,993	303,738	301,483	299,228	296,973	294,717	292,462	290,207	287,952	3,604,264
Equity Return	723,506	718,289	713,073	707,856	702,639	697,422	692,205	686,988	681,771	676,554	671,337	666,120	8,337,761
Total Return on Rate Base	1,036,265	1,028,793	1,021,321	1,013,849	1,006,377	998,905	991,433	983,961	976,489	969,017	961,544	954,072	11,942,025
Income Statement Items													
Book Depreciation	920,277	920,277	920,277	920,277	920,277	920,277	920,277	920,277	920,277	920,277	920,277	920,277	11,043,321
Deferred Taxes	241,185	241,185	241,185	241,185	241,185	241,185	241,185	241,185	241,185	241,185	241,185	241,185	2,894,217
Gross Up for Income Tax	229,401	226,230	223,060	219,889	216,719	213,548	210,377	207,207	204,036	200,866	197,695	194,524	2,543,551
Total Income Statement Expense	1,390,862	1,387,692	1,384,521	1,381,351	1,378,180	1,375,009	1,371,839	1,368,668	1,365,498	1,362,327	1,359,156	1,355,986	16,481,090
Total Revenue Requirement	2,427,128	2,416,485	2,405,842	2,395,200	2,384,557	2,373,914	2,363,272	2,352,629	2,341,986	2,331,344	2,320,701	2,310,058	28,423,115
Rider Eligible Revenue Requirement	133,173	132,589	132,005	131,421	130,838	130,254	129,670	129,086	128,502	127,918	127,334	126,750	1,559,539
ADIT Prorate Adjustment	167	167	167	167	167	167	167	167	167	167	167	167	1,999
Total Rider Eligible Revenue Requirement	133,340	132,756	132,172	131,588	131,004	130,420	129,836	129,252	128,668	128,084	127,500	126,916	1,561,538
Courtenay Wind													
Rate Base													
Plant In-Service	305,344,482	305,344,482	305,344,482	305,344,482	305,344,482	305,344,482	305,344,482	305,344,482	305,344,482	305,344,482	305,344,482	305,344,482	305,344,482
Less Accumulated Book Depreciation Reserve	13,932,284	14,964,380	15,996,476	17,028,573	18,060,669	19,092,765	20,124,862	21,156,958	22,189,054	23,221,151	24,253,247	25,285,344	25,285,344
Less Accumulated Deferred Taxes	79,684,522	80,329,091	80,973,660	81,618,229	82,262,798	82,907,367	83,551,936	84,196,504	84,841,073	85,485,642	86,130,211	86,774,780	86,774,780
End Of Month Rate Base	211,727,676	210,051,011	208,374,346	206,697,680	205,021,015	203,344,350	201,667,685	199,991,019	198,314,354	196,637,689	194,961,024	193,284,358	193,284,358
Return on Rate Base													
Debt Return	412,732	409,477	406,221	402,966	399,710	396,455	393,199	389,944	386,688	383,433	380,177	376,922	4,737,923
Equity Return	954,776	947,245	939,714	932,183	924,652	917,121	909,590	902,059	894,527	886,996	879,465	871,934	10,960,260
Total Return on Rate Base	1,367,508	1,356,721	1,345,935	1,335,148	1,324,362	1,313,575	1,302,789	1,292,002	1,281,216	1,270,429	1,259,643	1,248,856	15,698,184
Income Statement Items													
Book Depreciation	1,032,096	1,032,096	1,032,096	1,032,096	1,032,096	1,032,096	1,032,096	1,032,096	1,032,096	1,032,096	1,032,096	1,032,096	12,385,156
Deferred Taxes	644,569	644,569	644,569	644,569	644,569	644,569	644,569	644,569	644,569	644,569	644,569	644,569	7,734,827
Gross Up for Income Tax	30,154	25,577	21,000	16,423	11,846	7,269	2,692	(1,885)	(6,462)	(11,039)	(15,616)	(20,193)	59,766
Total Income Statement Expense	1,706,819	1,702,242	1,697,665	1,693,088	1,688,511	1,683,934	1,679,357	1,674,780	1,670,203	1,665,626	1,661,049	1,656,472	20,179,749
Total Revenue Requirement	3,074,327	3,058,964	3,043,600	3,028,237	3,012,873	2,997,510	2,982,146	2,966,782	2,951,419	2,936,055	2,920,692	2,905,328	35,877,933
Rider Eligible Revenue Requirement	168,390	167,548	166,705	165,863	165,021	164,179	163,337	162,495	161,652	160,810	159,968	159,126	1,965,094
ADIT Prorate Adjustment	445	445	445	445	445	445	445	445	445	445	445	445	5,345
Total Rider Eligible Revenue Requirement	168,835	167,993	167,151	166,309	165,466	164,624	163,782	162,940	162,098	161,256	160,413	159,571	1,970,439

Reference

Att. F

Att. F

Note: Rider Eligible Requirements are calculated using both Energy and Demand allocators from the separate Production and Transmission components of the project

Production Tax Credits					
	2015	2016	2017	2018	
	<i>Actual</i>	<i>Mixed</i>	<i>Forecast</i>	<i>Forecast</i>	<i>Reference</i>
<u>Border Winds</u>					
Wind Production (MWh)	31,560	572,415	533,325	533,325	
PTC Credit per MWh	23	23	23	23	
PTC Value	726,000	13,166,000	12,266,000	12,266,000	
Allocator	5.4518%	5.4868%	5.4707%	5.4707%	
PTC North Dakota Jurisdiction	39,580	722,397	671,033	671,033	
Gross Up for Income Taxes	1.6078	1.6078	1.6078	1.6078	
PTC Revenue Requirement	(63,635)	(1,161,437)	(1,078,858)	(1,078,858)	<i>Att. B-F</i>
<u>Courtenay Wind</u>					
Wind Production (MWh)	-	39,324	637,769	678,478	
PTC Credit per MWh	23	23	23	23	
PTC Value	-	904,000	14,669,000	15,605,000	
Allocator	5.4518%	5.4868%	5.4707%	5.4707%	
PTC North Dakota Jurisdiction	-	49,601	802,494	853,699	
Gross Up for Income Taxes	1.6078	1.6078	1.6078	1.6078	
PTC Revenue Requirement	-	(79,746)	(1,290,214)	(1,372,540)	<i>Att. B-F</i>

Operations & Maintenance Expense					
	2015	2016	2017	2018	
	<i>Actual</i>	<i>Mixed</i>	<i>Forecast</i>	<i>Forecast</i>	<i>Reference</i>
<u>Border Winds</u>					
Contract/Consulting	393,936	4,222,879	4,714,038	4,165,759	
Space/Lease Costs	47,238	566,853	566,853	566,853	
Materials	1,984	10,550	-	315,238	
Other	75,018	408,795	38,545	39,087	
Total O&M Costs	518,175	5,209,076	5,319,436	5,086,937	
Allocator	5.4056%	5.2249%	5.2525%	5.2525%	
O&M North Dakota Jurisdiction	28,011	272,171	279,405	267,193	<i>Att. B-F</i>
<u>Courtenay Wind</u>					
Contract/Consulting		1,356,325	5,597,208	5,679,692	
Space/Lease Costs		-	1,170,000	1,192,400	
Materials					
Other			460,000	685,000	
Total O&M Costs	-	1,356,325	7,227,208	7,557,092	
Allocator	5.4056%	5.2249%	5.2525%	5.2525%	
O&M North Dakota Jurisdiction	-	70,867	379,611	396,938	<i>Att. B-F</i>

North Dakota Calendar Month Electric Sales (Mwh)
 2017 Budget

ANNUAL Summary											
	Residential w/o Sp Heat	Residential w/ Sp Heat	Total Residential	Small C&I	Large C&I	Total C&I	Street Lighting	Public Authority	Interdept	Total Other	Total Retail
2016	132,540	76,928	209,468	276,964	86,237	363,201	4,715	3,157	0	7,872	580,541
2017	518,215	261,913	780,128	1,095,884	350,635	1,446,518	15,290	13,600	0	28,890	2,255,537
2018	519,068	263,239	782,307	1,099,045	349,941	1,448,986	15,141	13,600	0	28,741	2,260,033
2017 Budget											
	Residential w/o Sp Heat	Residential w/ Sp Heat	Total Residential	Small C&I	Large C&I	Total C&I	Street Lighting	Public Authority	Interdept	Total Other	Total Retail
Oct-16	36,820	15,981	52,801	86,888	29,305	116,193	1,352	981	0	2,333	171,327
Nov-16	42,682	25,790	68,472	90,855	30,038	120,893	1,675	1,032	0	2,706	192,072
Dec-16	53,038	35,157	88,195	99,221	26,894	126,115	1,688	1,145	0	2,833	217,143
Total 16	132,540	76,928	209,468	276,964	86,237	363,201	4,715	3,157	0	7,872	580,541
Jan-17	55,124	40,975	96,099	101,362	27,133	128,495	1,788	1,190	0	2,978	227,571
Feb-17	46,085	32,691	78,776	84,663	26,222	110,885	1,543	1,002	0	2,544	192,206
Mar-17	42,969	28,703	71,672	95,163	29,578	124,742	1,206	1,209	0	2,415	198,828
Apr-17	33,753	16,324	50,077	80,880	26,803	107,683	1,141	1,070	0	2,211	159,971
May-17	34,661	14,334	48,995	85,999	30,185	116,184	893	1,262	0	2,155	167,334
Jun-17	40,003	11,735	51,739	88,031	30,535	118,566	893	1,089	0	1,982	172,287
Jul-17	49,497	14,226	63,723	98,664	30,693	129,358	886	1,231	0	2,117	195,197
Aug-17	46,347	13,515	59,862	96,546	31,124	127,670	987	1,129	0	2,116	189,648
Sep-17	36,494	12,056	48,550	87,186	31,711	118,898	1,274	1,262	0	2,536	169,984
Oct-17	36,915	15,997	52,912	86,809	29,439	116,249	1,341	981	0	2,321	171,482
Nov-17	42,836	25,912	68,748	91,043	30,171	121,213	1,665	1,032	0	2,696	192,657
Dec-17	53,532	35,445	88,976	99,537	27,039	126,577	1,674	1,145	0	2,818	218,372
Total 17	518,215	261,913	780,128	1,095,884	350,635	1,446,518	15,290	13,600	0	28,890	2,255,537
Jan-18	55,245	41,301	96,547	102,679	27,081	129,760	1,782	1,190	0	2,972	229,278
Feb-18	46,095	32,968	79,063	84,425	26,165	110,590	1,537	1,002	0	2,539	192,191
Mar-18	43,010	28,880	71,890	95,080	29,518	124,598	1,194	1,209	0	2,402	198,891
Apr-18	34,121	16,476	50,597	82,537	26,742	109,279	1,122	1,070	0	2,192	162,068
May-18	34,580	14,361	48,941	85,294	30,080	115,373	870	1,262	0	2,132	166,447
Jun-18	40,056	11,706	51,762	87,726	30,474	118,200	885	1,089	0	1,974	171,936
Jul-18	49,605	14,269	63,875	99,107	30,644	129,751	878	1,231	0	2,109	195,734
Aug-18	46,461	13,494	59,954	96,725	31,073	127,798	977	1,129	0	2,106	189,858
Sep-18	36,502	12,090	48,592	86,871	31,665	118,536	1,262	1,262	0	2,524	169,652
Oct-18	36,922	16,009	52,931	87,448	29,405	116,853	1,327	981	0	2,308	172,093
Nov-18	42,840	25,979	68,819	91,325	30,112	121,438	1,651	1,032	0	2,683	192,939
Dec-18	53,631	35,706	89,337	99,828	26,982	126,810	1,656	1,145	0	2,801	218,947
Total 18	519,068	263,239	782,307	1,099,045	349,941	1,448,986	15,141	13,600	0	28,741	2,260,033

2017 kWh:
 2,255,536,676 Att. A

Rate/kWh from Att. A	Revenues (sales x rate)
\$0.000898	204,433
\$0.000898	172,663
\$0.000898	178,612
\$0.000898	143,705
\$0.000898	150,320
\$0.000898	154,769
\$0.000898	175,351
\$0.000898	170,366
\$0.000898	152,701
\$0.000898	154,046
\$0.000898	173,069
\$0.000898	196,169
	2,026,203 Att. E

	Universal Inputs			
	2015	2016	2017	2018
Book Depreciation				
Net Salvage %				
Production	-4.60%	-4.60%	-4.60%	-4.60%
Transmission	-8.63%	-8.63%	-8.63%	-8.63%
TSG	-34.45%	-34.45%	-34.45%	-34.45%
Land Rights	0.00%	0.00%	0.00%	0.00%
Book Depreciation Lives				
Production	25.00	25.00	25.00	25.00
Transmission	64.28	64.28	64.28	64.28
TSG	80.42	80.42	80.42	80.42
Land Rights	25.00	25.00	25.00	25.00
Book Depreciation Rates (Composite)				
Production	4.18%	4.18%	4.18%	4.18%
Transmission	1.69%	1.69%	1.69%	1.69%
TSG	1.67%	1.67%	1.67%	1.67%
Land Rights	4.00%	4.00%	4.00%	4.00%
Tax Rates				
Income Tax Rates				
State Income Tax Rate	4.31%	4.31%	4.31%	4.31%
Federal Income Tax Rate	35.00%	35.00%	35.00%	35.00%
Composite Income Tax Rate				
State Composite Income Tax Rate	37.8015%	37.8015%	37.8015%	37.8015%
Company Composite Income Tax Rate	40.7980%	40.7980%	40.7980%	40.7980%
Property Tax Rate	1.075%	0.790%	0.790%	0.790%
Cap Structure (Last Authorized)				
Long Term Debt %	44.96%	44.96%	44.96%	44.96%
Long Term Debt Cost	5.14%	5.14%	5.14%	5.14%
Short Term Debt %	2.48%	2.48%	2.48%	2.48%
Short Term Debt Cost	0.75%	0.75%	0.75%	0.75%
Weighted Cost of Debt	2.33%	2.33%	2.33%	2.33%
Common Stock %	52.56%	52.56%	52.56%	52.56%
Common Stock Cost	10.00%	10.25%	10.25%	10.25%
Preferred Stock %	0.00%	0.00%	0.00%	0.00%
Preferred Stock Cost	0.00%	0.00%	0.00%	0.00%
Weighted Cost of Equity	5.26%	5.39%	5.39%	5.39%
Allocators				
ND 12-month CP energy (Electric Energy)	6.4765%	6.5597%	6.5140%	6.5140%
NSPM 36-month CP demand (Interchange Electric)	84.5789%	84.1349%	84.2332%	84.2332%
Wind Jurisdictional Allocator	5.4778%	5.5190%	5.4870%	5.4870%
ND 12-month CP demand (Electric Demand)	6.3912%	6.2102%	6.2357%	6.2357%
NSPM 36-month CP demand (Interchange Electric)	84.5789%	84.1349%	84.2332%	84.2332%
Trans Jurisdictional Allocator	5.4056%	5.2249%	5.2525%	5.2525%
ND 12-month CP energy (Electric Energy)	6.4765%	6.5597%	6.5140%	6.5140%
NSPM Interchange Energy (Interchange Electric)	84.1786%	83.6446%	83.9834%	83.9834%
PTC Jurisdictional Allocator	5.4518%	5.4868%	5.4707%	5.4707%

Legislative

NORTH DAKOTA ELECTRIC RATE BOOK - NDPSC NO. 2

RENEWABLE ENERGY RIDER

Section No. 5

~~3rd~~^{4th} Revised Sheet No. 87

APPLICATION

Applicable to qualifying charges for electric service provided under all Company retail rate schedules.

RENEWABLE ENERGY RIDER

There will be included on each customer's monthly bill a Renewable Energy Rider ("RER") charge for purposes of recovering capital and operating costs of company-owned renewable energy generation located in the state of North Dakota and not presently reflected in base retail rates. The RER charge shall be determined by multiplying a customer's monthly billed kWh for electric service by the current RER Rate. The RER charge shall be calculated prior to the application of any city surcharges and/or sales tax.

DETERMINATION OF RER RATE

The RER Rate is determined by dividing the annual forecasted RER revenue requirement amount by the annual forecasted kWh sales. The annual forecasted RER revenue requirement is the sum of the RER costs for the forecast period and the carryover balance in the RER Tracker Account from the prior period. The RER Rate will be calculated annually, with the approval of the Commission. The present RER Rate is:

All Classes

~~\$0.000936~~\$0.000898 per kWh

C

All approved costs appropriately charged to the RER Tracker Account are eligible for recovery through this Rider, and all revenues recovered through the Rider are credited to the RER Tracker Account.

QUALIFYING RENEWABLE ENERGY RIDER COSTS

Qualifying RER costs include all annual revenue requirements eligible for recovery under N.D.C.C. § 49-02, 49-05 and 49-06. These costs include, but are not limited to, depreciation expense, property taxes, and operation and maintenance expenses related to Company-owned renewable energy project costs and capacity-related renewable energy purchased power costs not currently being recovered in base rates or eligible for recovery through the FCR. Eligible projects (or portions of these projects) must be located in the state of North Dakota and must have previously been granted an Advance Determination of Prudence by the Commission.

TRUE-UP

For each calendar year the RER is in place, a true-up adjustment to the Tracker Account will be calculated reflecting the difference between actual RER revenue and the actual RER costs (revenue requirements) for the recovery period. The true-up shall be recorded by May 1 of the following calendar year and will be included in the calculation of the RER rate effective for the next calendar year recovery period.

For example, Year 1 actual RER revenue will be compared to the actual RER revenue requirements for the same period and the difference recorded as an adjustment to the Tracker Account on or before May 1 of Year 2. This difference would then be included in the calculation of the new RER Rate to be filed with the Commission later in Year 2, and effective January 1 of Year 3.

Date Filed: ~~10-01-15~~11-01-16

By: Christopher B. Clark

Effective Date: ~~01-01-16~~

President, Northern States Power Company, a Minnesota corporation

Case No. PU-~~15-683~~

Order Date: ~~12-16-15~~

Non-Legislative

NORTH DAKOTA ELECTRIC RATE BOOK - NDPSC NO. 2

RENEWABLE ENERGY RIDER

Section No. 5
4th Revised Sheet No. 87

APPLICATION

Applicable to qualifying charges for electric service provided under all Company retail rate schedules.

RENEWABLE ENERGY RIDER

There will be included on each customer's monthly bill a Renewable Energy Rider ("RER") charge for purposes of recovering capital and operating costs of company-owned renewable energy generation located in the state of North Dakota and not presently reflected in base retail rates. The RER charge shall be determined by multiplying a customer's monthly billed kWh for electric service by the current RER Rate. The RER charge shall be calculated prior to the application of any city surcharges and/or sales tax.

DETERMINATION OF RER RATE

The RER Rate is determined by dividing the annual forecasted RER revenue requirement amount by the annual forecasted kWh sales. The annual forecasted RER revenue requirement is the sum of the RER costs for the forecast period and the carryover balance in the RER Tracker Account from the prior period. The RER Rate will be calculated annually, with the approval of the Commission. The present RER Rate is:

All Classes	\$0.000898 per kWh
-------------	--------------------

C

All approved costs appropriately charged to the RER Tracker Account are eligible for recovery through this Rider, and all revenues recovered through the Rider are credited to the RER Tracker Account.

QUALIFYING RENEWABLE ENERGY RIDER COSTS

Qualifying RER costs include all annual revenue requirements eligible for recovery under N.D.C.C. § 49-02, 49-05 and 49-06. These costs include, but are not limited to, depreciation expense, property taxes, and operation and maintenance expenses related to Company-owned renewable energy project costs and capacity-related renewable energy purchased power costs not currently being recovered in base rates or eligible for recovery through the FCR. Eligible projects (or portions of these projects) must be located in the state of North Dakota and must have previously been granted an Advance Determination of Prudence by the Commission.

TRUE-UP

For each calendar year the RER is in place, a true-up adjustment to the Tracker Account will be calculated reflecting the difference between actual RER revenue and the actual RER costs (revenue requirements) for the recovery period. The true-up shall be recorded by May 1 of the following calendar year and will be included in the calculation of the RER rate effective for the next calendar year recovery period.

For example, Year 1 actual RER revenue will be compared to the actual RER revenue requirements for the same period and the difference recorded as an adjustment to the Tracker Account on or before May 1 of Year 2. This difference would then be included in the calculation of the new RER Rate to be filed with the Commission later in Year 2, and effective January 1 of Year 3.

Date Filed: 11-01-16

By: Christopher B. Clark

Effective Date:

President, Northern States Power Company, a Minnesota corporation

Case No. PU-

Order Date: