

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-17-398
OAH File No. 20170622

Exhibit ____

TRANSITION OF CAPITAL PROJECTS FROM RIDERS TO BASE RATES

Rebuttal Testimony and Schedule of

Bryce C. Haugen

June 22, 2018

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Schedule 1 – MISO MVP Project Status December 2017

1 **I. INTRODUCTION**

2 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

3 A. My name is Bryce C. Haugen, and my address is 215 South Cascade Street, Fergus Falls,
4 Minnesota 56537.

5

6 Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

7 A. I am employed by Otter Tail Power Company (OTP or the Company) as Senior Rates
8 Analyst, Regulatory Administration.

9

10 Q. DID YOU PREPARE DIRECT AND SUPPLEMENTAL DIRECT TESTIMONY IN
11 THIS PROCEEDING?

12 A. Yes. I filed Direct Testimony on behalf of OTP on various issues including: (1) moving
13 investments currently being recovered in the Environmental Cost Recovery Rider
14 (ECRR), Transmission Cost Recovery Rider (TCRR) and the Renewable Resource
15 Adjustment Rider (RRAR) into base rates, including the treatment of RRAR-related
16 Production Tax Credits (PTCs); and (2) advertising expenses. My Supplemental Direct
17 Testimony addressed the cost of debt in the ECRR, RRAR and TCRR calculations, the
18 ECRR, RRAR and TCRR peak demand factors and the impact of the Tax Cuts and Jobs
19 Act (TCJA) on PTCs in the RRAR.

20

21 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

22 A. The purpose of my Rebuttal Testimony is to respond to the Direct Testimony of Mr.
23 Ralph C. Smith filed on behalf of the North Dakota Public Service Commission (the
24 Commission) Advocacy Staff (Staff), and the Direct Testimony of Ms. Kavita Maini and
25 Mr. Larry L. Schedin filed on behalf of the Midwest Large Energy Consumers (MLEC). I
26 also explain OTP's agreement with uncontested issues raised by the Mr. Smith.

27

1 **II. SUMMARY OF REBUTTAL TESTIMONY**

2 Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

3 A. OTP’s customers have received \$27.2 million (OTP ND) in revenue requirement
4 reductions as a result of crediting PTC’s as they are “generated” but prior to them being
5 used by OTP to reduce OTP’s actual tax expense. Ms. Maini requests the Commission
6 change course and tie the rate impact of PTCs to the actual usage of PTCs on tax returns.
7 Ms. Maini’s recommendation regarding PTCs should not be adopted because it creates an
8 inconsistency in how PTC’s have been recognized and normalized.

9 Mr. Schedin’s recommendation regarding a Key Performance Incentive (KPI) for
10 OTP’s transmission vice president is unnecessary. OTP has controlled the costs of its
11 transmission projects and the MISO transmission planning process contains its own form
12 of cost-control. Mr. Schedin ultimately asks the Commission to insert itself into the day-
13 to-day management of OTP. His recommendation should be rejected.

14 Finally, OTP does not possess the data Mr. Schedin requests regarding wind
15 turbine maintenance. His testimony also does not recognize the unique nature of the
16 operations and maintenance services provided for OTP’s wind projects.

17 **III. CONTESTED ISSUES**

18 **A. DEFERRED TAX ASSET IN RRAR [MLEC-MAINI]**

19 Q. WHAT IS A DEFERRED TAX ASSET?

20 A. A deferred tax asset is an accounting on a utility’s balance sheet that represents tax
21 credits and other tax benefits that have been used to lower rates before those credits or
22 benefits have been recognized on the utility’s tax return (and therefore have not yet
23 reduced the utility’s actual tax expense). The deferred tax asset is ultimately a measure
24 of benefits given to customers in advance of a reduction in the cost of service. The value
25 of the deferred tax asset changes as deferred tax benefits are actually reflected on tax
26 returns (thus reducing the amount of the asset) and as new tax credits and other benefits
27 are “generated” but cannot be used and are thus deferred (thus increasing the amount of
28 the asset).

1 Q. CAN PTCs RESULT IN A DEFERRED TAX ASSET?

2 A. Yes. PTCs are credits against taxable income. If a utility's PTCs exceed its taxable
3 income (after recognizing other tax benefits with a higher priority, as explained below),
4 then the unused PTCs are added to the deferred tax asset for future use.

5

6 Q. ARE PTCs THE ONLY MEANS OF OFFSETTING TAXES?

7 A. No. There are a variety of tax treatments, deductions and credits that can be used to
8 minimize taxable income and ultimately, tax expense. These include accelerated
9 depreciation, bonus depreciation, all deductions, net operating loss (NOL) carryforwards
10 and investment tax credits (ITCs).

11

12 Q. IS THERE A PRIORITY AMONG THESE TAX OFFSETS?

13 A. Yes. From a tax planning perspective, deductions and credits that must be utilized in the
14 current year are effectively given the highest priority in their use on current tax returns
15 because if they are not used, they are lost. PTCs and other items that can be carried
16 forward are of lower priority for purposes of their use on current tax returns, and are only
17 utilized after all deductions and credits that cannot be carried forward are exhausted.

18

19 Q. DOES THE FACT THAT PTCs AND OTHER TAX BENEFITS THAT CAN BE
20 CARRIED FORWARD ARE CONSIDERED TO BE OF LOWER PRIORITY MEAN
21 THEY ARE LESS VALUABLE?

22 A. No. The priority of tax offsets only refers to necessity of using the tax treatment sooner
23 rather than later. "Lower priority" tax benefits such as PTCs can be carried forward to
24 future periods, and higher priority tax deductions and other tax treatments cannot.
25 Another way to think of a tax benefit's priority, is to consider what the priority is of using
26 it sooner rather than later. If a tax benefit must be used sooner (or be lost), it is said to be
27 of higher priority, but that does not mean it has higher value. Tax planning optimization
28 involves the sequencing (or prioritizing) of tax benefits so that the timing of the use of
29 specific tax benefits on tax returns is optimized for the largest benefit over time. But each
30 offset is of equal value in the sense they reduce tax expense.

1 Q. WHAT IS THE BALANCE OF OTP'S UNUSED PTCS?

2 A. OTP projects that as of September 2018, the cumulative balance of unused PTCs will be
3 \$13.7 million (OTP ND).¹

4
5 Q. WHY HAVE PTCS BEEN UNUSED?

6 A. PTCs have been unused on OTP's tax returns because tax deductions and treatments with
7 a higher priority have been used to fulfill prior and current tax returns and the value of
8 the PTCs has been carried forward to optimize OTP's overall tax position. Even though
9 the unused PTCs have not reduced current or prior period taxes for OTP, OTP has
10 reflected their tax reduction value in rates, consistent with the settlement approved by the
11 Commission in Case Nos. PU-08-862 and PU-08-742. Through this approach, OTP's
12 North Dakota customers have received the rate reduction benefits associated with PTCs
13 even in those instances when OTP has not yet utilized them on tax returns.

14
15 Q. PLEASE EXPLAIN HOW NORTH DAKOTA CUSTOMERS HAVE RECEIVED PTC
16 BENEFITS EVEN THOUGH OTP HAS NOT BEEN ABLE TO UTILIZE ALL OF ITS
17 PTCS.

18 A. Under the terms of the settlement in Case Nos. PU-08-862 and PU-08-742, PTCs are
19 credited to customers at the time they are "earned" (*i.e.* when the kWhs that give rise to
20 the credits are generated) through a dollar-for-dollar reduction in the RRAR income tax
21 expense, even if OTP cannot yet use those PTCs on the current period tax return.²

22
23 Q. WHAT IS THE CUMULATIVE AMOUNT OF PTC BENEFITS RECEIVED BY
24 NORTH DAKOTA CUSTOMERS THROUGH LOWER RATES?

25 A. Through April 2018, North Dakota customers have been credited \$27.2 million (OTP
26 ND) through the RRAR for PTCs generated at OTP's wind farms. OTP projects its North

¹ Maini Direct, Attachment 5 (OTP Response to ND-MLEC-150).

² OTP and Staff testimony in Case No. PU-16-14 provides additional detail regarding the current crediting of PTCs within the RRAR. Alternative methods, including spreading the generated PTCs out over the life of the facility, have been discussed in Case Nos. PU-08-862, PU-08-742 and PU-16-14. The Commission has found that the PTCs for Langdon and Ashtabula should be credited to customers immediately. *See* Commission June 22, 2016 Order in Case No. PU-16-14 and Commission November 25, 2008 Order in Case Nos. PU-08-862 and PU-08-742.

1 Dakota customers will receive an additional \$0.5 million (OTP ND) of PTC credits from
2 May 2018 through September 2018.

3
4 Q. HAS OTP SEEN A CORRESPONDING REDUCTION IN ITS COST OF PROVIDING
5 SERVICE?

6 A. No. OTP's tax optimization has resulted in OTP not being able to yet utilize \$13.7
7 million (OTP ND) of PTCs as of the end of September 2018. These unutilized PTCs are
8 carried forward to offset future taxable income and are part of the deferred tax asset.

9
10 Q. ARE THERE OTHER WAYS TO REFLECT PTCS IN RATES?

11 A. Yes. Tax benefits are generally "normalized," which means spread over a reasonable
12 period, in order to confer to an equitable portion of the tax benefits to all customers
13 paying bills over some longer period of time, rather than conferring benefits just to those
14 customers paying rates in the years the tax benefits are reflected on a utility's tax return.
15 Probably the most common form of normalization is the treatment of accelerated
16 depreciation. Accelerated depreciation front-loads the depreciation associated with an
17 asset (which reduces taxable income and therefore tax expenses) on the tax returns of the
18 utility. But for ratemaking, the benefit is "normalized" by spreading the tax benefit over
19 the entire depreciable life of the asset rather than allocating the entire tax benefit only to
20 those customers paying bills in the early years of the life of the asset.

21 The approach approved in Case Nos. PU-08-862 and PU-08-742 is different. The
22 PTC benefits are not spread over the entire lives of the projects; rather, they are
23 incorporated into rates in each year PTC's are "generated" (based on the kWhs generated
24 in each of the first ten years), regardless of whether OTP's tax optimization strategies
25 result in PTCs being used on the then-current-period tax return. If OTP had waited to
26 reflect the PTCs in rates until they were actually reflected on a tax return, customer rates
27 paid since the projects were completed would have been higher.

28

- 1 Q. PRIOR TO FILING THIS RATE CASE, WAS THE PORTION OF THE DEFERRED
2 TAX ASSET ATTRIBUTABLE TO UNUSED PTCS LOCATED IN THE RRAR?
- 3 A. Yes.
4
- 5 Q. IS THE PORTION OF THE DEFERRED TAX ASSET ATTRIBUTABLE TO
6 UNUSED PTCS INCLUDED IN THE 2018 TEST YEAR RATE BASE?
- 7 A. Yes. OTP proposes to roll the Langdon, Ashtabula and Luverne wind project investments
8 currently included in the RRAR into base rates at the time final rates go into effect. This
9 includes all gross plant in service, forecasted accumulated depreciation and associated
10 deferred income tax balances, which includes the deferred tax asset.
11
- 12 Q. IS OTP'S PROPOSAL CONSISTENT WITH THE SETTLEMENT IN OTP'S LAST
13 RATE CASE?
- 14 A. Yes.³
15
- 16 Q. PLEASE SUMMARIZE MS. MAINI'S RECOMMENDED TREATMENT OF THE
17 PTC-RELATED PORTION OF OTP'S DEFERRED TAX ASSET.
- 18 A. Ms. Maini recommends that the PTC-related portion of OTP's deferred tax asset continue
19 to be tracked through the RRAR and resulting changes to revenue requirements be
20 updated through the RRAR on an annual basis.⁴
21
- 22 Q. IS MS. MAINI'S PROPOSAL CONSISTENT WITH THE COMMISSION'S PRIOR
23 TREATMENT OF PTCS?
- 24 A. No. The Commission has consistently found that customers should receive credit for
25 Langdon and Ashtabula PTCs, regardless of OTP's ability to realize cost savings through
26 utilization of PTCs on its tax returns. Now that customers have received \$27.2 million
27 (OTP ND), through April 2018, in PTC-related rate reductions (without corresponding

³ July 1, 2009 Settlement Agreement in Case Nos. PU-08-742 and PU-08-862, page 8.

⁴ Maini Direct, pages 9-11.

1 cost reductions), Ms. Maini wants to change course and re-tether PTCs to actual usage on
2 tax returns.

3
4 Q. IS IT REASONABLE TO SINGLE OUT THE PTC-RELATED PORTION OF OTP'S
5 DEFERRED TAX ASSET FOR DIFFERENT RATEMAKING TREATMENT?

6 A. No. As noted above, while the portion of the deferred tax asset identified by Ms. Maini
7 may be equal to the unused balance of PTCs, it is overly simplistic to attribute the
8 deferred tax asset entirely to the PTCs. Rather, the deferred tax asset was created through
9 comprehensive tax planning that seeks to minimize tax expense by optimizing the use of
10 all available mechanisms. OTP's deferred tax obligations will in the future result in
11 increased tax expense from its operations and only then will the PTCs be useable on tax
12 returns. If the tax asset value changes as PTCs are used, it will reflect only one aspect of
13 OTP's actual changes to tax expense and related accountings. For example, if Ms.
14 Maini's proposal were to be accepted, OTP could argue that its tax expense should also
15 be updated each time the tax asset is reduced for PTCs now reflected on tax returns.

16
17 Q. IS MS. MAINI'S PROPOSAL IN CONFLICT WITH THE TAX EXPENSE USED TO
18 SET RATES IN THIS CASE?

19 A. Yes. The 2018 Test Year income tax expense has been minimized by utilizing deductions
20 and credits, consistent with comprehensive tax planning principles and Internal Revenue
21 Service (IRS) requirements. This is a real benefit to customers that will be locked into
22 rates. OTP anticipates that 2019 current-year deductions and credits will be lower than
23 what is reflected in the 2018 Test Year, requiring utilization of some accumulated PTCs.
24 Under Ms. Maini's proposal, customers get the benefit of both the low tax expense
25 reflected in the 2018 Test Year *and* depletion of the deferred tax asset – without any
26 corresponding re-assessment of overall tax expense.

27
28 Q. ARE THERE OTHER WAYS TO ADDRESS TAXES?

29 A. Yes. In theory, *all* tax items (rate base and expense) could be removed from base rates
30 and tracked between rate cases. A tax tracker would provide optimum alignment between

1 tax-related cost items and what customers pay, but achieving that alignment comes at a
2 cost of additional regulatory proceedings. It would also be a departure from traditional
3 North Dakota practice. More importantly, this would ultimately result in higher rates for
4 customers, not lower rates, and OTP does not recommend such an approach. Instead,
5 OTP recommends that the changes to its tax expense and tax assets/liabilities for base
6 rate assets be reviewed and reflected in its next general rate case.

7
8 Q. DOES MS. MAINI PROPOSE A TAX TRACKER?

9 A. No. Ms. Maini does not contemplate other tax related impacts in future years based on
10 PTC utilization in her Direct Testimony and only proposes tracking the PTC-related
11 portion of OTP's deferred tax asset.

12
13 Q. WHAT DOES OTP RECOMMEND?

14 A. OTP continues to recommend that the entire project investments and all project
15 components, including the PTC-related portion of the deferred tax asset, for Langdon and
16 Ashtabula be rolled out of the RRAR and into base rates at the time final rates go into
17 effect.

18 **B. TRANSMISSION COSTS [MLEC-SCHEDIN]**

19 Q. PLEASE SUMMARIZE MR. SCHEDIN'S RECOMMENDATION REGARDING
20 OTP'S TRANSMISSION COST CONTROL.

21 A. Mr. Schedin expresses concerns over rising transmission costs and recommends OTP
22 implement a Key Performance Incentive (KPI) for its transmission vice president aimed
23 at controlling costs of major transmission projects.⁵

24
25 Q. DOES OTP ALREADY WORK TO CONTROL THE COSTS OF ITS MAJOR
26 TRANSMISSION PROJECTS?

27 A. Yes. OTP is the project manager for its two, largest ever transmission investments, the
28 Big Stone Area Transmission to Brookings County (BSAT-Brookings) 345kV

⁵ Schedin Direct, p. 5-8.

1 transmission project and the Big Stone Area Transmission to Ellendale (BSAT-Ellendale)
2 345kV transmission project.⁶ The original cost estimate for BSAT-Brookings was \$226.7
3 million (Total Project) / \$133.5 million (OTP Total). BSAT-Brookings was completed in
4 September 2017 at a cost of \$141 million (Total Project)⁷ / \$73 million (OTP Total), with
5 the Total Project being approximately *37 percent under budget*. BSAT-Ellendale is also
6 currently projected to be completed at or below its budgeted cost.

7
8 Q. DOES THE MISO TRANSMISSION PLANNING PROCESS PROTECT AGAINST
9 OVER-ESTIMATING PROJECT BUDGETS?

10 A. Yes. Midcontinent Independent System Operator (MISO) assesses new transmission
11 projects through MISO's transmission expansion plans (MTEP) process. A transmission
12 project must be found to have economic benefits at the budgeted amount before moving
13 forward in the MTEP process. A project that does not provide economic benefit does not
14 meet the criteria to be approved.

15
16 Q. WHY IS THIS IMPORTANT?

17 A. Mr. Schedin forwards the concern that a utility may inflate its project budget to prevent
18 cost overruns.⁸ There is an inherent cost safeguard in the MTEP process that requires that
19 economic benefit be found at the budgeted amount. If those budgets are artificially
20 inflated beyond the benefits identified, the project would not move forward through the
21 MTEP process.

22
23 Q. HAS MISO PREPARED ANY STUDIES ASSESSING THE COSTS AND BENEFITS
24 OF ITS MAJOR TRANSMISSION PROJECTS?

25 A. Yes. As shown in Figure 1 below, MISO's September 2017 MTEP17 MVP Triennial
26 Review showed MISO's Multi-Value Project (MVP) portfolio yielded a benefit-to-cost
27 ratio of 2.2 to 3.4, resulting in \$12.1 to \$52.6 billion in net benefits to customers over the

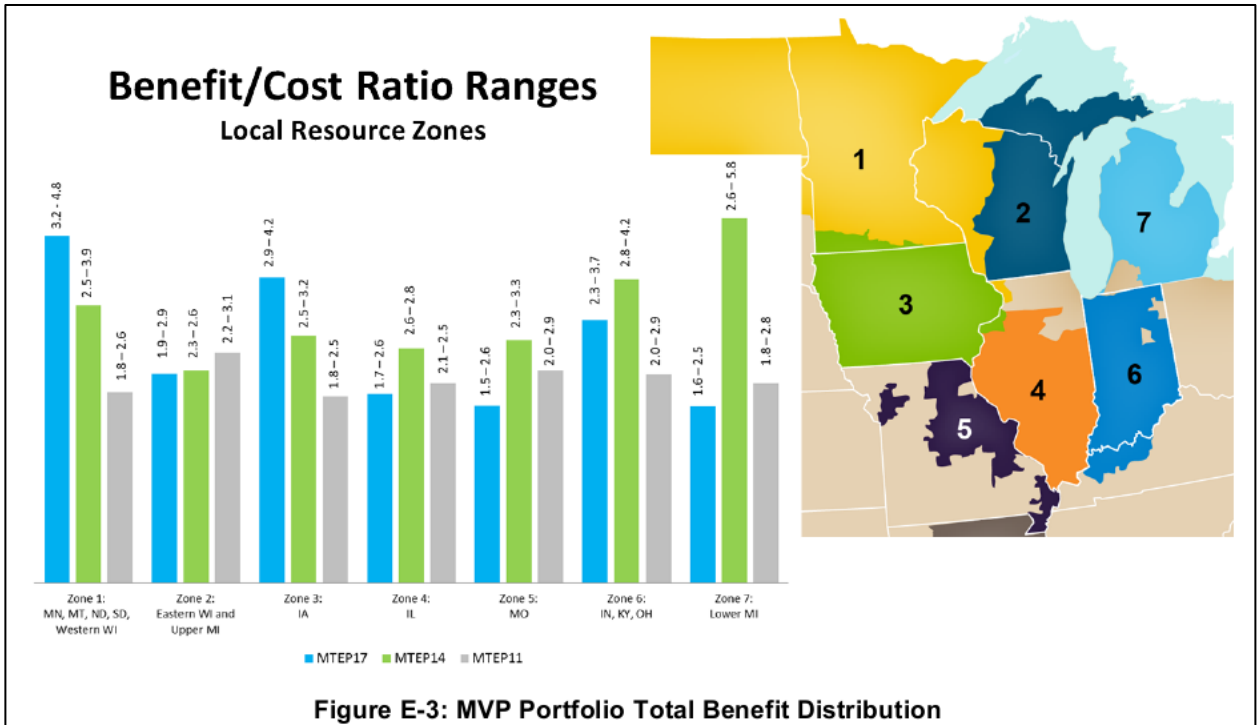
⁶ Mr. Schedin's testimony incorrectly alludes to another party being the project manager for these projects. Schedin Direct, p. 6.

⁷ Exhibit___(BCH-3), Schedule 1.

⁸ Schedin Direct, p. 7.

1 next 20-40 years.⁹ Customers in North Dakota receive the highest amount of benefits-to-
 2 costs, ranging from 3.2-4.8.

3
 4 **Figure 1**
 5 **MISO MTEP17 Benefit/Cost Ratio Ranges¹⁰**
 6



7 **Figure E-3: MVP Portfolio Total Benefit Distribution**
 8

9 Q. DOES THE COMMISSION REVIEW OTP'S TRANSMISSION COSTS PRIOR TO
 10 OTP'S RECOVERY THROUGH RATES?

11 A. Yes. OTP provides annual updates to its TCRR that details the costs of transmission
 12 projects. In these annual updates, OTP provides status updates for projects that were
 13 previously approved and also provides project overviews for new projects it requests for
 14 inclusion in the TCRR.

15
⁹ MISO MTEP17 MVP Triennial Review, p. 4 (Sept. 2017), available at
<https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf>.

¹⁰ MISO MTEP17 MVP Triennial Review, p. 8 (Sept. 2017), available at
<https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf>.

1 Q. DO OTP'S ANNUAL UPDATES TO ITS TCRR DISCUSS COSTS OTP IS
2 REQUIRED TO PAY UNDER FEDERAL TARIFFS?

3 A. Yes. Our annual updates provide details regarding federally-assessed transmission costs. I
4 also note that the compounded annual growth rate (CAGR) related to these federally-
5 mandated costs that are included in our TCRR, over which OTP has no control, is 22.76
6 percent.¹¹ Using Mr. Schedin's Table 1, corrected to remove "Other MISO (net)" from
7 the "Non-MISO" column, the non-MISO related CAGR is 4.22 percent from 2014 to
8 2018.¹²

9
10 Q. HAS COMMISSION STAFF PROVIDED RECOMMENDATIONS TO APPROVE
11 THESE ANNUAL UPDATES TO COSTS IN THE TCRR?

12 A. Yes. Commission Staff filed memos in each of OTP's annual TCRR updates
13 recommending approval after its review of all components in the TCRR. Case Numbers
14 for these TCRR annual updates are included in my Direct Testimony.¹³

15
16 Q. ARE THERE OTHER CONCERNS REGARDING MR. SCHEDIN'S
17 RECOMMENDATION?

18 A. Yes. Selection and design of incentive targets is a core aspect of the day-to-day
19 management of OTP.¹⁴ Mr. Schedin invites the Commission to insert itself into this
20 process, contrary to the broad recognition that management lies with the company.¹⁵

21 There are also practical concerns with Mr. Schedin's recommendation. It has been
22 eight years since OTP's last rate case; before that, it had been 25 years since OTP filed a

¹¹ The CAGR of Mr. Schedin's Table 1 column entitled "Other MISO (net)" is $(\$2,969/\$1,065)^{(1/5\text{years})}-1 = 22.76$ percent. The "Other MISO (net)" revenue requirements are embedded in the "Non-MISO" column of Mr. Schedin's Table 1 which leads to double counting in the "Total" column of his Table 1.

¹² The CAGR of Mr. Schedin's corrected Table 1 column entitled "Non-MISO" is $(\$5,413/\$4,588)^{(1/4\text{years})}-1 = 4.22$ percent.

¹³ Haugen Direct, page 17, table 5.

¹⁴ OTP Witness Mr. Peter E. Wasberg describes the design of OTP's Annual Incentive Plan on pages 3-7 of his Direct Testimony.

¹⁵ For example, the Colorado Supreme Court has stated "It is of course generally accepted that the management of the utility belongs to the company.... The PUC may not, under the guise of rate regulation, take over the management of the company." Colorado-Ute Elec. Ass'n, Inc. v. Pub. Util. Comm'n, 760 P.2d 627, 639 (Colo. 1988).

1 rate case. It is unrealistic to ask the Commission to design an incentive mechanism that
2 would be concrete enough to be meaningful while being dynamic enough to remain in
3 effect for several years without review.

4 Finally, given OTP's demonstrated ability to bring in projects under-budget, it is
5 unreasonable to ask the Commission to take the unusual and difficult step to craft a
6 meaningful incentive program.

7
8 Q. PLEASE SUMMARIZE OTP'S POSITION ON MR. SCHEDIN'S KPI
9 RECOMMENDATION.

10 A. OTP does not agree that additional KPI incentives need to be implemented as
11 recommended by Mr. Schedin.

12 **C. WIND TURBINE MAINTENANCE [MLEC-SCHEDIN]**

13 Q. PLEASE SUMMARIZE MLEC'S RECOMMENDATION REGARDING WIND
14 TURBINE MAINTENANCE.

15 A. Mr. Schedin recommends OTP provide comparative data from other wind farms to
16 compare OTP's wind farm maintenance expense.

17
18 Q. PLEASE EXPLAIN OTP'S WIND FARM OPERATIONS AND MAINTENANCE
19 EXPENSE.

20 A. OTP's wind farms are in a unique position in terms of operations and maintenance
21 expense. Our wind farms are part of larger NextEra wind farms. Thus, OTP pays for only
22 a part of the operation and maintenance expense team, with the other portion paid by
23 NextEra for maintenance at its associated farms.

24 NextEra has provided operations and maintenance since the start of operations. At
25 commercial operation date, OTP entered into a five-year contract with NextEra for
26 operation and maintenance with one-year extensions after the initial five-year period.
27 This contract was part of the build-transfer negotiations with NextEra. In 2014, OTP
28 evaluated third party proposals for the operation and maintenance of OTP-owned wind
29 farms. NextEra was the lowest cost provider and we executed another five-year contract.
30 We intend to solicit proposals again in 2020.

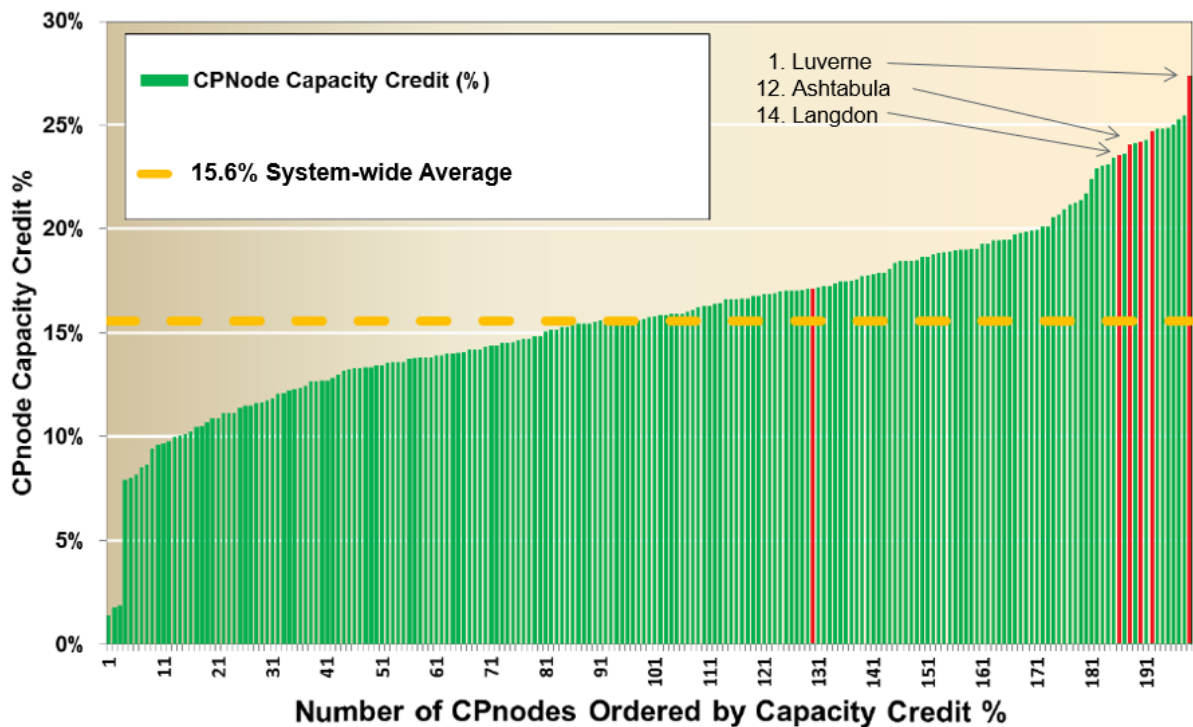
1 Q. HAVE OTP'S WIND FARMS EXPERIENCED PERFORMANCE-RELATED
2 PROBLEMS?

3 A. No. As shown in Figure 2 below, OTP wind farms have consistently provided some of
4 the highest capacity factors within the MISO footprint. This highlights that the
5 maintenance being performed is allowing OTP wind farms to capture North Dakota's
6 wind resource at an optimal level to the benefit of OTP's customers.

7
8

Figure 2

**Otter Tail's Performance Relative to all other
Wind Farms located within MISO's Footprint**



9
10

11 Q. DOES OTP HAVE COMPARATIVE WIND TURBINE MAINTENANCE DATA
12 FROM OTHER FARMS?

13 A. No. OTP does not have any comparative maintenance data from other wind farms. We
14 have relied on competitive bids to determine lowest total cost operations and maintenance
15 for our wind farms.

16

1 Q. DOES OTP AGREE WITH MLEC’S RECOMMENDATION TO PROVIDE
2 COMPARATIVE WIND TURBINE MAINTENANCE DATA?

3 A. OTP does not agree that it should provide comparative wind turbine maintenance data.

4 **IV. NON-CONTESTED ISSUE: RIDER ROLL-IN [STAFF-SMITH]**

5 Q. PLEASE SUMMARIZE MR. SMITH’S RECOMMENDATION REGARDING OTP’S
6 PROPOSAL TO ROLL IN-SERVICE PROJECTS FROM RIDERS INTO BASE
7 RATES.

8 A. Mr. Smith agrees with OTP’s proposal to transfer the recovery of in-service projects from
9 the ECRR, RRAR, and TCRR into base rates at the conclusion of the case. Mr. Smith
10 clarifies that the roll-in amounts reflected in base rates should be the plant balances at the
11 time of roll-in.¹⁶

12
13 Q. DOES OTP PROPOSE TO ROLL-IN TO BASE RATES, AND OUT OF THE
14 RESPECTIVE RIDER, THE PROJECT AMOUNTS AS OF THE DATE THAT FINAL
15 RATES ARE IMPLEMENTED?

16 A. Yes. OTP proposes to provide the actual balances at the time of roll-in to base rates and
17 out of the respective riders.

18 **V. CONCLUSION**

19 Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

20 A. OTP’s customers have received \$27.2 million (OTP ND) in rate reductions as a result of
21 crediting PTC’s as they are “generated” but prior to them being used to reduce OTP’s
22 actual tax expense. Ms. Maini’s recommendation regarding PTCs should not be adopted
23 as it creates an inconsistency in how PTC’s have been recognized and normalized.

24 Mr. Schedin’s recommendation regarding a Key Performance Incentive (KPI) for
25 OTP’s transmission vice president is unnecessary and should not be adopted.

¹⁶ Smith Direct, p. 72-93.

1 Finally, OTP does not possess the data Mr. Schedin requests regarding wind
2 turbine maintenance and his recommendations should not be adopted.

3

4 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

5 A. Yes.



Regionally Cost Allocated Project Reporting Analysis
 2011 MVP Portfolio Analysis Report

MVP Project Status December 2017

MVP No.	Project Name	State	Estimated in Service Date ¹		Status		Cost ²			Explanation ⁶
			MTEP Approved	August 2017	State Regulatory Status	Construction	MTEP Approved ³	MTEP Approved Dollars Adjusted to Estimated ISD ⁴	December 2017 ⁵	
1	Big Stone - Brookings	SD	2017	2017	●	Complete	\$227	\$263	\$141	
2	Brookings, SD - SE Twin Cities	MN/SD	2011-2015	2013-2015	●	Complete	\$738	\$738*	\$670	
3	Lakefield Jct - Winnebago - Winco - Burt area & Sheldon - Burt Area - Webster	MN/IA	2015-2016	2015-2018	●	Underway	\$550	\$654	\$651	A - E
4	Winco - Lime Creek - Emery - Black Hawk - Hazleton	IA	2015	2015-2019	●	Underway	\$469	\$571	\$564	B, C, D & E
5	N. LaCrosse - N. Madison - Cardinal (a/k/a Badger - Coulee Project)	WI	2018	2018	●	Underway	\$798	\$1,073	\$1,016	A, F
	Cardinal - Hickory Creek	WI/IA	2020	2023	○	Pending				A, D, F
6	Big Stone South - Ellendale	ND/SD	2019	2019	●	Underway	\$331	\$403	\$320	
7	Ottumwa - Zachary	IA/MO	2017-2020	2018-2019	●	Pending	\$152	\$186	\$226	A,B,C,D
8	Zachary - Maywood	MO	2016-2018	2016-2019	●	Pending	\$113	\$137	\$172	A, D, E
9	Maywood - Herleman - Meredosia - Ipava & Meredosia - Austin	MO/IL	2016-2017	2016-2017	●	Underway	\$432	\$501	\$723	A, B
10	Austin - Pana	IL	2018	2016-2017	●	Underway	\$99	\$115	\$135	A,B
11	Pana - Faraday - Kansas - Sugar Creek	IL/IN	2018-2019	2015-2019	●	Underway	\$318	\$388	\$423	A,B
12	Reynolds - Burr Oak - Hiple	IN	2019	2018	●	Underway	\$271	\$322	\$388	B,C
13	Michigan Thumb Loop Expansion	MI	2013-2015	2012-2015	●	Complete	\$510	\$563	\$504	
14	Reynolds - Greentown	IN	2018	2013-2018	●	Underway	\$245	\$299	\$388	B
15	Pleasant Prairie - Zion Energy Center	WI	2014	2013	●	Complete	\$29	\$30	\$36	E, F
16	Fargo - Sandburg - Oak Grove	IL	2014-2019	2016-2018	●	Pending	\$199	\$237	\$198	
17	Sidney - Rising	IL	2016	2016	●	Complete	\$83	\$94	\$88	
Total							\$5,564	\$6,573	\$6,645	

Footnotes:

- ¹ Estimated ISD provided by constructing Transmission Owners.
- ² Costs stated in millions.
- ³ MTEP11 approved cost estimates provided by constructing Transmission Owners.
- ⁴ MTEP11 approved cost estimates escalated to the estimated in-service year dollars based on MISO's 2.50% annual inflation rate.
- ⁵ Current cost estimates provided by constructing Transmission Owners. This represents the estimated cost for ratebase purposes.
- ⁶ Explanation for cost variance beyond annual inflation escalation. See below for explanation.
- * MTEP11 approved cost estimate was provided in nominal (expected year of spend) dollars.

State Regulatory Status Indicator Scale	
○	Pending
◐	In regulatory process or partially complete
●	Regulatory process complete or no regulatory process Requirements

Explanations

- A. Regulatory Requirements
- B. Engineering & Design Standards
- C. Material / Commodity Pricing
- D. Schedule Delay
- E. Costs associated with delayed ISD
- F. Other

Examples: Detailed information can be found in the MTEP Quarterly Status Update (<https://www.misoenergy.org/Library/Pages/ManagedFileSet.aspx?SetId=1945>).
 Routing changes, timing delays, structure changes, and equipment modifications necessary to fulfill regulatory requirements.
 Modifications to foundations, structures, lines, and substations resulting from detail design, route selection and/or new NERC standards.
 Price escalation variances above and beyond standard escalation assumption (including labor).
 Increased cost due to changes in scheduling and, if applicable, the resulting higher AFUDC.
 Route changes due to legal or right-of-way issues, changes in material availability or costs, and new standards.
 Described in the MTEP Quarterly Status Update.