Evaluation of Otter Tail Power Company's Acquisition of the Astoria Generating Station and Merricourt Project as the Least Cost Options Compared to Other Alternatives

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On Behalf of

South Dakota Commission Staff
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A. Introduction

On May 31, 2019, Otter Tail Power Company (OTP) submitted its petition to the South Dakota Public Utilities Commission (Commission) for approval of its initial rate for the Phase-In Rate Plan Rider. The rider seeks to recover actual costs and forecasted costs associated with the Astoria Simple Cycle Generating Plant (Astoria) and the Merricourt Wind Project (Merricourt). The South Dakota Public Utilities Commission granted OTP the opportunity to seek recovery of the two generating projects through a Phase-in Rate Plan Rider, in Docket EL18-021.

On behalf of Commission Staff, KM Energy Consulting, LLC (KM_EC) was tasked with evaluating whether the acquisition of Astoria and Merricourt were least cost options compared to other alternatives in order to reliably serve energy and capacity needs. In order to evaluate this issue, efforts were made to assess (a) the energy and capacity needs and (b) Present Value of the Revenue Requirements (PVRR) impacts associated with selecting the two projects compared to other alternatives.

Astoria is an approximately 250 MW natural gas-fired, frame-style, simple cycle combustion turbine generation facility to be located near Astoria, South Dakota. The expected in-service date is December 2020. As indicated in the petition, Otter Tail will own and operate this generation resource once construction is complete. The project includes all associated facilities, including a short segment of natural gas pipeline necessary to interconnect to the Northern Border Pipeline, and a generation-tie line necessary to connect Astoria Station to the electric grid. The project will be designed with quick-start capability to serve a load-following function and provide for peak capacity needs. The cost of this project is estimated at $165 million. The petition indicates that OTP expects to complete the project at or under this budgeted amount.

Merricourt is a wind energy generation facility located in Merricourt, North Dakota. According to the petition, this project will consist of 75 V110-2.0 MW Vestas wind turbine generators with an aggregate nameplate capacity of 150 MW. The project's energy output is expected to be approximately 666,000 megawatt hours (MWh) annually, at a projected net capacity rate of 50.7 percent. Merricourt will interconnect to Montana-Dakota Utilities Company's Merricourt 230 kV substation located approximately 13 miles southwest of Kulm, North Dakota. OTP has a signed

Interconnection Agreement. The Merricourt project is a turn-key project that will be developed and constructed by subsidiaries of EDF Renewable Energy, Inc. (EDF). The cost of this project is estimated at $270 million. Project construction has begun and this project is expected to be in service in the Fall of 2020.

B. Needs Assessment

The following factors are contributing to the need to acquire generation resources by 2021:

1. **Hoot Lake Retirement.** OTP intends to retire Hoot Lake in 2021. The Hoot Lake plant is solely owned by OTP and consists of two coal-fired units and is located in Minnesota. The two units will be 57 and 62 years old in 2021, respectively, and have a combined capacity of approximately 140 MW. OTP began analyzing its system needs associated with the Hoot Lake Plant in 2010. OTP conducted a Baseload Diversification Study in 2012 and determined that making minimal investments for the Mercury and Air Toxic Standards (MATS) regulations compliance (estimated at $10 million on a company-wide basis)[1] and then retiring Hoot Lake Plant Units 2 and 3 in 2021 was the least-cost option. Options such as repowering the plant or retiring the plant in 2015 were not cost effective. KM_EC evaluated the analysis on behalf of Staff in Docket EL14-082 and concluded that making the investment to be MATS compliant was least cost compared to other alternatives.

   When asked why repowering Hoot Lake was not a cost effective option compared to acquiring Astoria, OTP indicated the following in response to SDPUC-4-005:

   > The Hoot Lake Plant has reached the end of its useful life. Both Hoot Lake Units 2 & 3 will have in excess or nearly 60 years of service at the planned retirement date. Significant upgrades would be required for the reliability aspect of the existing equipment (i.e. repowering of the boilers, turbines, generators, fuel handling equipment, etc.). Pollution control equipment upgrades would also be required; for example, neither unit currently has any

[1] OTP reported that actual costs were $8.2 million including AFUDC.

sulfur dioxide control equipment and the plant utilizes once through cooling (as opposed to closed cycle cooling) for water management

Further, OTP also stated in the same response that the costs to repower Hoot Lake are higher than constructing Astoria. While the costs to repower Hoot Lake range from $167 million to $212 million, Astoria related costs are now estimated at $157.5 million. Further, the O&M costs are also lower. Thus, it is reasonable to retire the Hoot Lake plant.

2. **Purchase Power Agreements.** OTP entered into the following capacity purchase agreements intended to bridge its capacity needs until Hoot Lake Plant is retired in 2021 and additional generation is added to its portfolio:

- A 50 MW capacity-only contract with Great River Energy in 2014, increasing to 100 MW from January 2015 through May 31, 2017;
- A 25 MW capacity-only contract with Great River Energy that began on June 1, 2017 and runs through May 31, 2019, and increases to 50 MW capacity-only from June 1, 2019 through May 31, 2021; and
- A 55 MW capacity-only contract with Great River Energy that began on June 1, 2017 and runs through May 31, 2019.

Further, OTP also has an energy only purchase power agreement that expires in 2021.

3. **Load Growth.** Consistent with past IRPs, OTP's load growth shows an increasing trend primarily due to an increase in industrial load. OTP's 2016 IRP indicates that by the end of the study period, large commercial and industrial loads will increase to roughly 60% of the Company's retail sales. The 2016 IRP shows that the planning reserve margin obligation required by MISO increases from 795 MW in 2017 to 848 MW in 2021 and 938 MW by the end of the study period.[2]

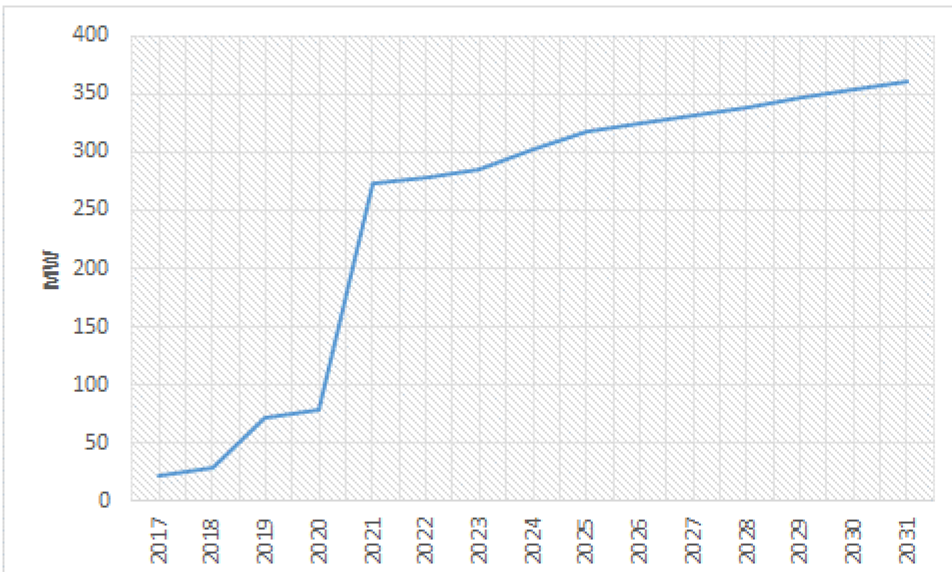
OTP used the same forecasting methodology in its 2016 IRP as the 2013 IRP. To test the reasonability of the forecast, the summer peak demand forecast for 2021 in the 2013 IRP was compared to what was forecasted in the 2016 IRP for the same year. The 2016 demand forecast

[2] OTP is a winter peaking utility. However, MISO's planning reserve margin requirements are based on OTP's summer peak coincident with MISO's peak.

was higher than the 2013 demand forecast. OTP attributed the increase primarily to increase in industrial loads and increase in MISO's planning reserve margin requirements. [3]

Thus, overall, OTP has reasonably demonstrated that it will be deficient from a capacity and energy standpoint as a result of the impending retirement of the Hoot Lake plant, expiring purchase power agreements and load growth. Figure 1 below shows the capacity deficiency by year from 2017-2031. As can be observed, the capacity deficiency is 273 MW by 2021 as a result of the factors described above. This deficiency is calculated after accounting for demand response and OTP's existing dependable capacity in each year.

Figure 1: Capacity Deficiency by Year (MW)



Further, OTP estimates that it will need to procure between 26% and 31% of its energy from the MISO market by 2021[4].

OTP would be significantly deficient from an energy and capacity perspective without taking action to acquire new supply side resources. OTP has reasonably demonstrated a need for supply side resources to reliably serve native load requirements.

[3] See response to SDPUC 4-006 Supplemental.
[4] Refer to Brian Draxten Testimony in ND Docket PU -17-140

C. Evaluation Against Other Alternatives

Since OTP has a capacity and energy deficiency, a combined cycle configuration is commonly considered to fulfill need. Combined cycle generation has the ability to follow load by ramping up and down throughout the day while providing energy at lower marginal cost than a simple cycle generator (due to a lower heat rate) and with lower capital costs compared to a baseload generator.

Both Astoria and a combined cycle option are natural gas fired and therefore, natural gas price assumptions have a significant impact on the analysis. The reasonableness of the natural gas price forecast is discussed further below. Since the combined cycle technology utilizes a lower heat rate, the marginal cost of producing power is lower than from a simple cycle technology. Therefore, if natural gas prices are low, all things held equal, combined cycle technology would be more economical compared to a simple cycle generator from a variable cost standpoint. However, the capital costs for combined cycle are higher compared to a simple cycle generator. [5]

Table 2 shows the PVRR results of various scenarios to the base case option which consists of procuring from the market and not acquiring new resources. As can be noted from this table, the PVRR of the base plus Astoria and Merricourt combination (scenario 4) is lower compared to the base case and several other scenarios including base cases that include either Astoria or Merricourt individually or combined cycle options[6].

[5] OTP's IRP shows that in 2017 dollars, the simple cycle capital cost was $599/KW and the combined cycle cost was $1,047/KW. The capital cost for the combined cycle was obtained from Wood Mackenzie as noted in response to SDPUC 8.4 h in Docket EL18-021.

[6] See response to SDPUC 8.4 in Docket EL18-021

Table 2: PVRR Results of the Sensitivity Analyses

	Scenario	Present Value Utility Costs (000)	Difference from Base (000)
1	Base Case (Market energy and capacity purchases)	2,375,341.8	
2	Base plus Astoria	2,338,913.8	(36,428.0)
3	Base plus Merricourt	2,262,374.0	(112,967.8)
4	Base plus Astoria and Merricourt	2,238,187.5	(137,154.3)
5	Base plus Astoria and Merricourt High Capital case	2,251,998.8	(123,343.0)
6	Base plus Astoria and Merricourt 40-year life	2,223,324.0	(152,017.8)
7	Base plus Combined Cycle (CC)	2,492,719.0	117,377.2
8	CC with NG Price at -50% of base	2,289,305.2	(86,036.6)
9	CC with NG Price at -25% of base	2,416,990.8	41,649.0
10	CC with NG Price at +25% of base	2,548,063.8	172,722.0
11	CC with NG Price at +50% of base	2,591,174.2	215,832.4
12	CC with NG Price at +100% of base	2,632,673.2	257,331.4

Table 3 shows a relative comparison of the base case plus Astoria and Merricourt with various base case and combined cycle sensitivities. As can be noted below, while the PVRR for the combined cycle option with natural gas at -50% results in a lower PVRR compared to the base case, the PVRR of this scenario is $51 million higher compared to the Astoria/Merricourt combination.

Table 3: Relative Comparison of PVRR Results

Scenario	Present Value Utility Costs ($000)	Difference from Astoria Plus Merricourt
Base plus Astoria and Merricourt	2,238,187.5	
Base plus Combined Cycle (CC)	2,492,719.0	254,532
CC with NG Price at -50% of base	2,289,305.2	51,118
CC with NG Price at -25% of base	2,416,990.8	178,803
CC with NG Price at +25% of base	2,548,063.8	309,876
CC with NG Price at +50% of base	2,591,174.2	352,987

The natural gas forecast was estimated by Wood Mackenzie, an established supplier that uses macroeconomic modeling analysis to produce such forecasts. Table 4 shows the Wood Mackenzie's base natural gas price forecast with EIA's reference price from 2016. The Wood Mackenzie's forecast shows a lower price trend compared to EIA.

Table 4: Natural Gas Price Comparison – Wood Mackenzie v. EIA Long Term Forecast

[Begin Confidential]

[redacted]

[End Confidential]

If the EIA assumptions had been used, the economics for the Astoria/Merricourt combination would have looked more positive, against the combined cycle options.[7] Based on the preceding observations, it can be concluded that the natural gas price forecast utilized by OTP is reasonable.

[7] Wood Mackenzie's forecast was also used by MISO in conjunction with EIA natural gas price forecast in the transmission expansion planning studies in 2016. See https://cdn.misoenergy.org/20160518%20PAC%20Item%2002c%20MTEP17%20Futures%20Update89615.pdf

D. Selection in the IRP

In the 2013 IRP, OTP analyzed a range of scenarios including combined cycle, various sizes of simple cycle plants, wind and solar. The 2013 IRP results showed that a 211 MW simple cycle plant was selected as part of a least cost plan. In Minnesota, the Commission also authorized OTP "to obtain up to 300 MW of wind in the 2017–2021 timeframe if cost-effective and to the extent consistent with reliable system operation."[8]

OTP's 2016 Resource Plan again analyzed a number of scenarios, including combined cycle generation, two sizes of natural gas simple cycle generation, wind, and solar. OTP ran 30 different sensitivity cases with and without externalities. The sensitivities included testing load growth assumptions, input fuel assumptions such as coal and natural gas prices and wind generation prices. The IRP results indicates that 200 MW of wind and 248 MW of a simple cycle plant were selected in all of the sensitivities conducted in the least cost plan, with and without externalities[9].

In response to SDPUC 4-003 Supplemental, OTP indicated that a higher MW size was selected in 2016 compared to 2013 (248MW in 2016 v. 211 MW in 2013) due to increase in load growth. OTP indicated that "the 248 MW size was the least cost option when considering size of capacity need and the relative cost of the turbine."

The assumptions used for a generic simple cycle plant in the IRP are consistent with the cost of Astoria at $665/KW[10]. Further, the EIA capital cost estimates for an advanced simple cycle plant were $678/KW (2016$) and higher than the Astoria estimated cost.[11] The IRP selected wind provided it was priced at $30/MWh prices for wind with a 40% capacity factor. The Merricourt project is estimated at roughly $22/MWh with a 50.7% capacity factor. In terms of $/KW cost, the Merricourt project is estimated at $1800/KW. EIA estimates for on shore wind is $1,877/KW (2016$). [12]

[8] See Minnesota Public Utility Commission Order in Docket:13-961.
[9] See Appendix I of the 2016 IRP
[10] See response to SDPUC 3.03
[11] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf
[12] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf

Thus, based on the evaluation of Otter Tail's IRP and the analysis conducted in the ADP proceeding in North Dakota, OTP has reasonably demonstrated that the Astoria/Merricourt combination is least cost compared to other alternatives.

E. Merricourt: Ownership vs. PPA

In Docket EL18-021, KM_EC evaluated whether it was more cost effective to enter into a purchase power agreement (PPA) with EDF (the project developer for Merricourt) or own the project.[13] Initially, OTP was evaluating a different wind technology with a 48.1% capacity factor. The levelized price comparison over a 25-year period indicated that the ownership option was more cost effective for that technology compared to EDF's offer:

[Begin Confidential]

- [redacted]
- [redacted]

[End Confidential]

Once OTP concluded that the ownership option was more cost effective, it started negotiating with EDF. OTP indicated in response to SDPUC 10.03 in Docket EL18-021 that:

> "[A] better-performing turbine became available in the context of EDF and OTP completing a turn key transaction --- well after OTP had conducted its levelized cost analysis. That a better performing turbine became available in the course of completing the transaction was not a basis to suspend the turn-key decision and associated negotiations in order to solicit new PPA proposals, in part because there was no reason to believe increased capacity factors would materially change the relatively economics between PPAs and the turn-key approach."

The levelized prices were calculated assuming 100% Federal PTC credit. In response to SDPUC 6.12 in Docket EL18-021, OTP indicated that:

> "The Merricourt project will need to be in operation by December 31, 2020 to be eligible to receive the 100% PTC credit. The Merricourt project has taken the necessary steps to meet the 5% safe harbor provisions as specified

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[13] In Docket EL18-021, KM_EC had reviewed PPA price proposals for wind in response to SDPUC 8.09 and concluded that the Merricourt PPA and Ownership options were more cost effective compared to other PPA proposals.

[14] EDF provided two offers and the levelized price above is the lower cost option. See response to SDPUC 13.27 in Docket EL18-021.

> in IRS guidance for the start of construction in 2016 by purchasing turbines and taking delivery of turbines."

In the petition, OTP reinforced that Merricourt is expected to be in service in the Fall of 2020. Consequently, Merricourt qualifies for the Federal PTC for the first 10 years of production.

The PTC credit is based on the amount of MWhs generated any given year (and therefore, the capacity factor) and is one of the most significant factors in reducing the cost of wind generation. A PPA arrangement is advantageous in that developers provide $/MWh PPA prices for wind generation which incorporate the PTC credits. Therefore, there is less risk associated with uncertainty in capacity factor. However, cost recovery is not levelized over the life of the project for the ownership option. Rather, standard ratemaking consists of front end loaded recovery of costs. A 1% drop in capacity factor results in increasing the levelized price for OTP by approximately $1/MWh. Given the narrow range between the PPA and the ownership option and the sensitivity associated with PTCs with respect to the economics, it was important to lock in the capacity factor of at least 50.7%[15] - this was accomplished in Docket EL18-021 as noted in Staff's Memo in that docket.[16]

F. Conclusion

In conclusion:

- OTP has reasonably demonstrated the need to acquire new resources given capacity and energy deficits.
- The Astoria/Merricourt combination is least cost compared to other resources.
- The Astoria/Merricourt combination is part of the least cost plan with or without externalities.
- OTP's ownership of Merricourt is reasonable considering that OTP has reduced the risk of uncertainty in the capacity factor by agreeing to utilize a capacity factor of at least 50.7%.

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[15] OTP has indicated that the capacity factor could be higher. See for example, workpapers in response to SDPUC 3-005.

[16] https://puc.sd.gov/commission/dockets/electric/2018/EL18-021/memo2.pdf.