Power System Engineering

FULL-SERVICE CONSULTANTS

North Dakota Transmission Capacity Study

Prepared for:

North Dakota Transmission Authority

Prepared by:

Power System Engineering, Inc.

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North Dakota Transmission Capacity Study
for the
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Authors:

Tom Butz

Laura Couillard

Peter Koegel

Curt Lyons

Contact: Peter A. Koegel, P.E.

koegelp@powersystem.org

Direct: 763-783-5351

Mobile: 651-269-8940

10710 Town Square Dr. NE, Suite 201
Minneapolis, MN 55449
www.powersystem.org

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1 Executive Summary

Power System Engineering, Inc. (PSE) was engaged by the North Dakota Transmission Authority (NDTA) to perform a study assessing the capacity of the North Dakota transmission system.

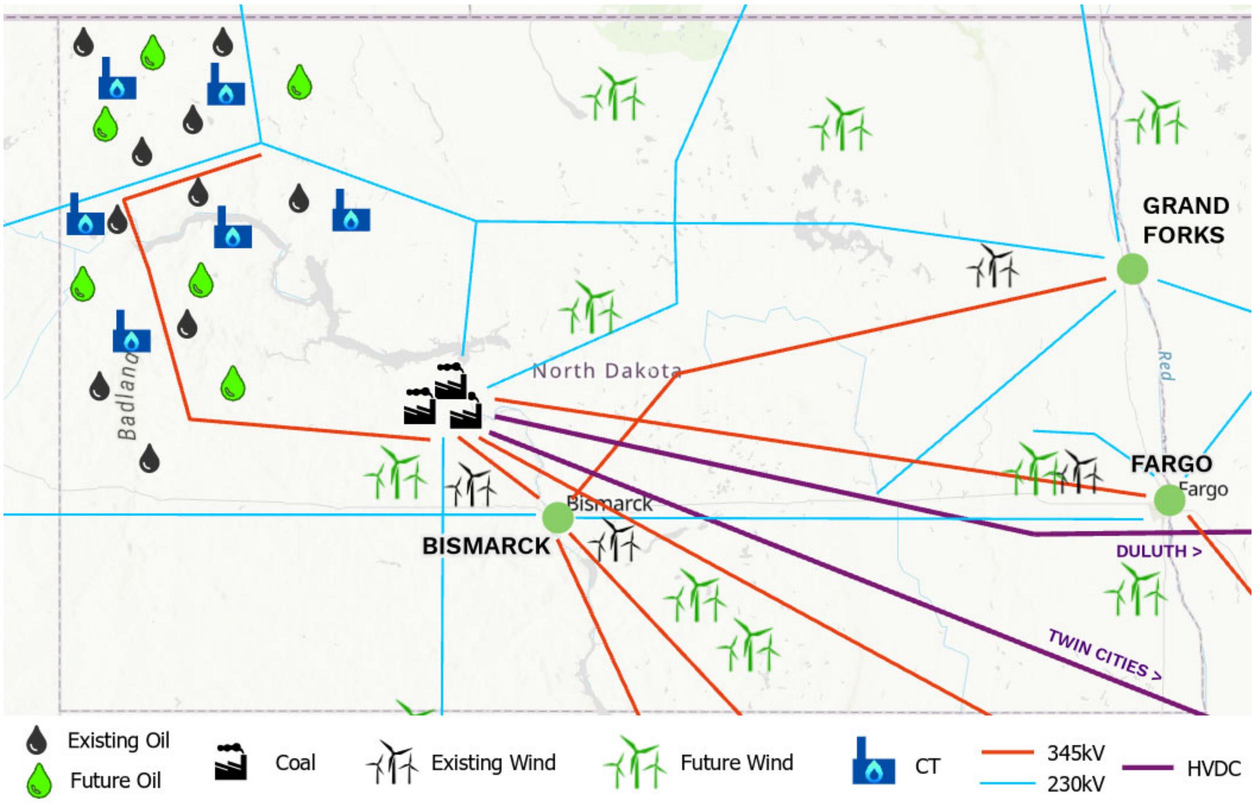

Figure 1-1: North Dakota Generation and Transmission Map

Observations from the study include:

- MISO and SPP Generation Interconnection Requests in North Dakota are greatly outpacing forecasted load growth and transmission expansion projects, utilizing the remaining transmission capacity and driving the need for expensive investment in the North Dakota transmission system.
- Roughly 80% of MISO and SPP Generation Interconnection Projects in North Dakota are unsuccessful due to expensive network upgrades assigned as mitigation, viability of the chosen Point of Interconnection, prospecting, and other reasons not publicly stated.
- Annual load growth in the Bakken Formation is around 1.2%, whereas the rest of North Dakota has a 0.8% annual load growth. Significant numbers of new generation requests and a lack of significant transmission expansion projects are projected to cause increases in power exports from the state along with transmission congestion and generation curtailments.
- AC powerflow analysis shows the number of thermal and voltage violations observed increasing dramatically from 2022 Summer Peak (28 thermal and 230 voltage violations)

to 2026 Summer Peak (2,881 thermal and 228 voltage violations) to 2038 Summer Peak (5,971 thermal and 624 voltage violations).

- Basis/LMP Pricing Analysis demonstrates that 2016-2019 MISO and SPP (MLC/MCC) values are negative in most locations of North Dakota.
- Monthly duration curves show increasing peaks and valleys in the $/MWHr pricing.
- The on-peak and off-peak basis comparisons of North Dakota generation nodes show both positive and negative historical trends, although the magnitudes in either direction in $/MWHr is minimal suggesting that there are no prime locations for generator additions based on Basis/LMP pricing signals alone.
- The 30% wind replacement analysis demonstrated that approximately 1,727 MW of additional wind generation would be required in order to provide the annual energy production of 5,600,000 MWh that would replace the assumed future retirement of a theoretical 900 MW of coal generation. This was an energy production and hourly load curve analysis performed outside of the transmission power flow models.
- The energy storage required to make this amount of wind energy fit into the system dispatch required a maximum charging capacity of over 831 MW and a maximum discharge output of over 1,831 MW. The total amount of energy storage required on the system for the 2018 analysis is 560,000 MWh. Transmission upgrades were not considered in lieu of energy storage for this analysis.
- North Dakota's transmission system is nearing full utilization of its existing capacity. Without the addition of significant new extra-high voltage (EHV: 345kV – 765kV) and high voltage (HV: 100kV – 345kV) AC and/or HVDC transmission capacity in the next 10-20 years, we expect fewer and fewer new generation interconnection projects to be built, the risk of voltage instability within the region to increase, and LMP pricing for existing generation to continue to decrease as transmission congestion continues to increase for generation exports out of the state into the regional MISO and SPP markets.
- Other study efforts looking at possible futures of significant renewable energy penetrations and robust transmission overlays including North Dakota are underway. One of these studies is the CapX2050 Transmission Vision Study[1].

[1] http://www.capx2020.com/

2 Phase 1: Transmission Capacity Research

2.1 Generation Interconnection Queue Review

Any new generation planned for North Dakota will be studied under the MISO, SPP, or Minnkota Power Cooperative (MPC) GI processes. These processes are conceptually similar but differ in key details. They were all initially based on the FERC pro-forma tariff, but have evolved over time to meet the needs of each organization as they respond to an unprecedented level of new Generator Interconnection Requests (GIR).

All three utilize group studies to process interconnection requests received as of a certain date. These studies are coordinated between MISO, SPP, and MPC, as well as other neighboring Independent System Operators (ISO), Regional Transmission Operators (RTO), and TOs, in order to establish a "queue priority" for each study group. This queue priority is used to allocate network capacity and identify cost responsibility for any network upgrades identified during the GI study process.

In total, as of September 1, 2019, there were 86 projects representing 11,666.6 MW summer, 11,690.6 MW winter of new generation within these GI Queues. Of these, 31 (2,964.4 MW Summer, 2,988.4 MW Winter) projects are in service; two (450 MW) projects are under construction or proceeding towards construction; and 53 (8,252.2 MW) projects are under study in the MISO, SPP, or MPC GI processes.

In MISO, we identified 21 In-Service projects, one Under Construction project, and 26 Active projects. A detailed list of these projects is provided in Table A-1. In SPP, we identified one In-Service project, one project with an Executed GIA, and 20 Active projects. A detailed list of these projects is provided in Table A-2. In MPC, we identified seven In-Service projects and seven Active projects. A detailed list of these projects is provided in Table A-3.

The GI study process is designed to identify any system upgrades required for the Bulk Electric System to operate safely and reliably with these proposed new generation projects interconnected. Any upgrades to the transmission system in North Dakota required for GI projects would be added to future versions of the applicable Transmission Expansion Plan (TEP).

2.2 Transmission Expansion Plan Review

PSE completed reviews of the MISO Transmission Expansion Plan (MTEP) Active Project list (as of April 15, 2019), the MTEP Appendix A Status Report (as of April 15, 2019), and the SPP 2019 Q1 Project Tracking Portfolio to identify local transmission projects that could impact power flows in North Dakota. MPC uses the MTEP process for its TEP projects. Thus, any projects submitted by MPC would be included in the MISO TEP review.

The MTEP19 Active Project list includes 18 Appendix A or B projects located in North Dakota. A few of these projects upgrade the 230kV network to accommodate new generation. It is expected that the estimated $5.7M 230kV network upgrades will only accommodate the new generation already approved for interconnection and not provide any significant increase in available capacity for the North Dakota network. The remaining $81.6M "Bottom Up" projects upgrade aging infrastructure or retire cap banks due to the evolving transmission system. The details of these 18 projects are provided in Table B-6.

The MTEP Appendix A Quarterly Status report (through April 15, 2019) includes 15 Appendix A projects from MTEP11 through MTEP18 located in or near North Dakota. Three of these projects are in-service, one is under construction, and the remaining 11 are planned to be completed in the near future. The details of these 15 projects are provided in Table B-7.

The SPP Transmission Expansion Plan (STEP) 2019 Q1 Project Tracking Portfolio includes nine projects located in North Dakota. Of these, six projects were in service by 2017. There are two new 115kV lines and four 115kV substation upgrades scheduled to be completed in the near future. The details of these projects are provided in Table B-8.

2.3 Current Study Review

In the past, MISO and SPP have occasionally performed specific studies to identify capacity issues and “bottlenecks” on the bulk electric system in various areas, including North Dakota. More recently, the periodic GI and annual TEP reliability studies have served this role. We did not identify any additional recent North Dakota transmission system studies that needed to be included in our review.

Observations and Conclusions drawn from the reviews discussed above were used to develop the scope of the transmission analysis performed in Phase 2 of the study.

3 Phase 2: Transmission Analysis

3.1 Steady-State Model Development

PSE used the following five PSS/E transmission power flow models for this analysis:

- MISO MTEP16 2021 Spring Light Load (21SLL)
- SPP 2017 Series 2022 Summer Peak (22SUM)
- MISO MTEP16 2026 Summer Peak (26SUM)
- SPP 2017 Series 2027 Winter Peak (27WIN)
- PSE Developed 2038 Summer Peak (38SUM)

PSS/E power flow models represent a single point in time, such as the peak hour in Summer for the Summer Peak model. Under these assumptions, the generator dispatch represents a capacity rather than a load factor.

3.1.1 Generation Dispatch

Many of the in-service North Dakota projects identified during the GI queue review have been in-service for years, with some dating back to the early 2000's. For the purpose of our analysis, we assumed that these projects are included in the study models. Projects identified as Under Construction or with an Executed Generator Interconnection Agreement (GIA) were confirmed to be modeled and left at the dispatch level modeled.

For Active projects, historically, we have seen less than 40% of the megawatts requested in the MISO and SPP GIR processes complete the Generator Interconnection Process (GIP) and sign a GIA; during recent study cycles, this percentage appears to be declining. Due to the large number of Active North Dakota GIRs in the MISO, MPC, and SPP queues, we modeled 20% of the megawatts from these GIRs rather than making assumptions about which individual projects might complete the process.

New generation added to the study models was sunk to the respective ISO/RTO/TO footprint and dispatched in each season based on the seasonal dispatch percentages of nameplate listed in Table 3-1 and then further reduced to 20% of those MWs. In addition, they were modeled with a 1.02 per unit voltage schedule at the Point of Interconnection (POI) and 95% power factor reactive power capability. Any proposed projects tapping a transmission line were modeled at a line-tap at the mid-point (50%) of the line.

Table 3-1: Added Generation Seasonal Dispatch Modeling Assumptions

Spring Light Load			Summer Peak			Winter Peak		
Gas	**Solar**	**Wind**	**Gas**	**Solar**	**Wind**	**Gas**	**Solar**	**Wind**
0%	0%	90%	100%	50%	15.6%	0%	50%	30%

The GIR projects located in North Dakota were dispatched in the transmission system power flow models based on the fuel type dispatch listed in Table 3-1 and the In-Service date listed in their respective queues. The industry standard cutoff dates for modeling are as follows:

- 2021 Spring Light Load Projects prior to April 15, 2021.

- 2022 Summer Peak Projects prior to July 15, 2022.
- 2026 Summer Peak Projects prior to July 15, 2026.
- 2027 Winter Peak Projects prior to January 15, 2028.

The MISO, MPC, and SPP GI Queues reviewed for this analysis do not contain any projects with In-Service dates in North Dakota beyond 2023. Thus, to represent a 38SUM model, all generation in the study area (including prior-queued generation) was increased at an assumed annual rate of 3%. Based on these assumptions, the total MW of generation dispatched from GI queue projects not yet in-service in each study model are shown in Table 3-2. The details of the projects added and their corresponding dispatch level are provided in Table A-4. Existing North Dakota wind generator dispatch data is provided in Table A-5.

Table 3-2: Generator Interconnection Queue Total MW Dispatch Additions

21SLL	22SUM	26SUM	27WIN	38SUM
1297.9	409.2	678.1	769.1	944.9

In addition to GI projects, PSE discussed fossil fuel generators and their dispatch levels with NDTA and several local TOs. Based on these conversations, the fossil units were dispatched in each of the study models as shown in Table 3-3.

Stanton was recently retired and was removed from the study models. Heskett Units 1 & 2 are also changing fuels during the time period of our analysis. However, we did not explicitly model this change in our analysis.

Table 3-3: Fossil Generation Dispatch

	21SLL		22SUM		26SUM		27WIN		38SUM
Generator	**Bench**	**Study**	**Bench**	**Study**	**Bench**	**Study**	**Bench**	**Study**	**Study**
Coal Creek Unit 1	224.7	224.7	610.1	610.1	610.1	610.1	610.1	610.1	610.1
Coal Creek Unit 2	345.0	345.0	617.0	617.0	617.0	617.0	617.0	617.0	617.0
Stanton	0.0	0.0	202.9	0.0	202.9	0.0	202.9	0.0	0.0
Center Unit 2	246.0	270.0	493.0	493.0	493.0	493.0	493.0	493.0	493.0
Center Unit 1	120.0	151.0	274.0	274.0	274.0	274.0	274.0	274.0	274.0
Antelope Valley Unit 1	465.0	465.0	465.0	465.0	465.0	465.0	465.0	465.0	480.0
Antelope Valley Unit 2	465.0	465.0	465.0	465.0	465.0	465.0	465.0	465.0	480.0
Leland Olds Unit 1	120.0	140.0	212.0	212.0	212.0	212.0	212.0	212.0	230.0
Leland Olds Unit 2	343.7	343.7	387.8	387.8	428.0	428.0	387.8	387.8	475.0
Coyote	300.0	300.0	453.0	453.0	453.0	453.0	453.0	453.0	453.0
Total Fossil Dispatch	***2629.4***	***2704.4***	***4179.8***	***3976.9***	***4220.0***	***4017.1***	***4179.8***	***3976.9***	***4112.1***

3.1.2 Load Growth

The load levels in the near-term and mid-term study models were set by Local Balancing Authorities (LBAs), TOs, and/or RTOs. Thus, PSE did not modify the load levels in these models.

To represent a 38SUM model, PSE created two load zones; the Williston Load Pocket and Outside the Williston Load Pocket. These zones encompass North Dakota and the electrical connections surrounding North Dakota. After discussions with NDTA and North Dakota Utilities and referencing the Power Forecast 2019 report[2], the load growth assumptions within the Williston

[2] BARR Engineering Power Forecast 2019: Williston Basin Oil and Gas Related Electrical Loa Growth Forecast, http://www.nd.gov/ndic/ic-press/Power%20Forecast%202019.pdf

Load Pocket were established at an annual rate of 1.18%, and load growth assumptions outside of the Williston Load Pocket were established at an annual rate of 0.78%. The overall load and generation totals included in each of our seasonal study models are represented in Figure 3-1.

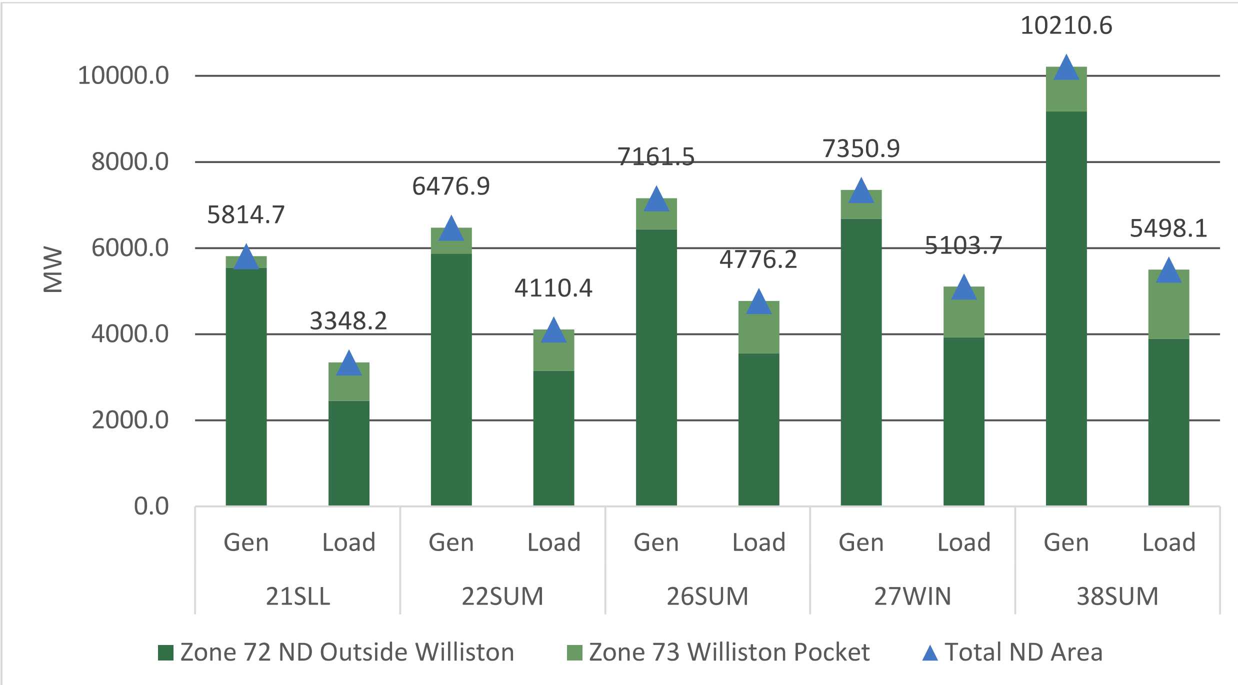

Figure 3-1: Load & Generation Total by Zone

A comparison of the summer peak study models load and generation totals is provided in Figure 3-2.

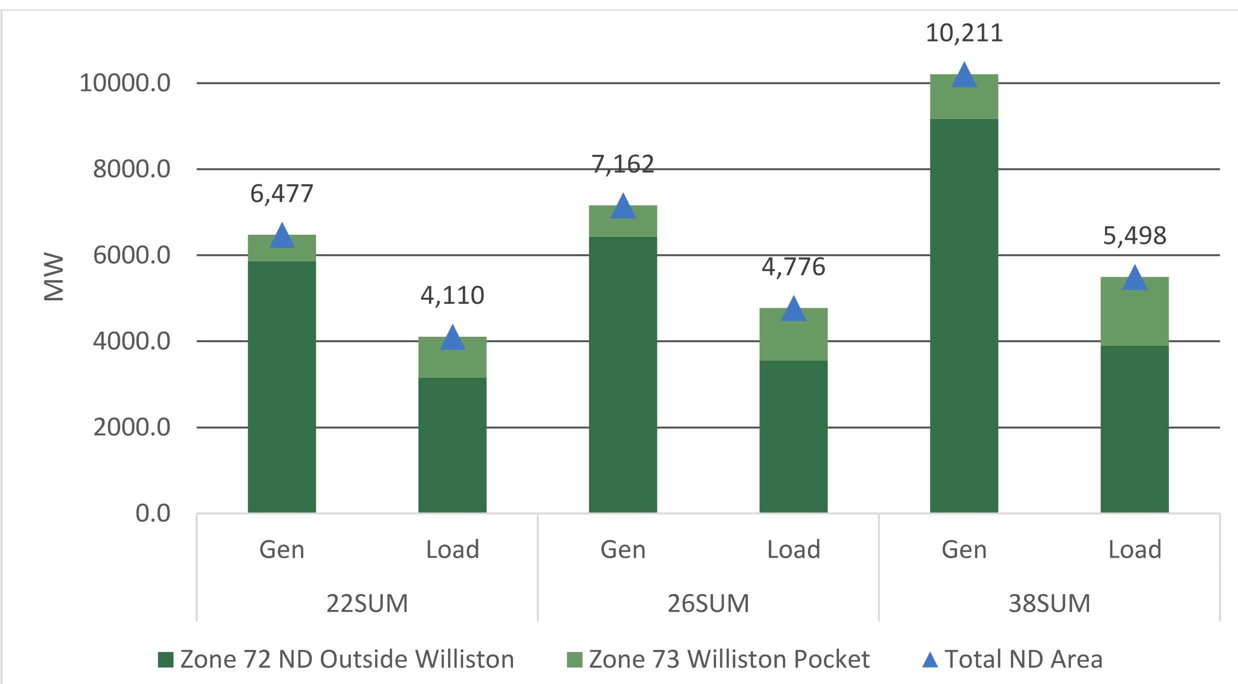

Figure 3-2: Summer Peak Load & Generation Totals

3.1.3 Transmission Expansion Planning Modifications

The MISO and SPP TEP reports did not identify any major North Dakota transmission expansion projects to be added to the study models. However, after discussions with NDTA, the following TEP projects were added.

- MTEP ID 15144: moved a 40MVAR capacitor bank modeled at the Bison 230kV bus to the Square Butte East 230kV bus.
- MTEP ID 15723: reduced the Prairie 115kV switched shunt from 12x40MVAR to 6x40MVAR. Recent MISO DPP studies have indicated that modifying this capacitor bank causes voltage issues in North Dakota. Therefore, the full capacitor bank size could be considered as mitigation should voltage issues arise.
- MTEP ID 15737: removed the Sheyenne 115kV switched shunt from the models. Recent MISO DPP studies have indicated that removing this capacitor bank causes voltage issues in North Dakota. Therefore, including this capacitor bank could be considered as mitigation should voltage issues arise.
- STEP PID 31032: added the Plaza 115kV substation, capacitor bank, and a transmission line to the Blaisdell 115kV substation to the MISO 21SLL and 26SUM models. The 115kV transmission line and capacitor bank were added based on the data for these facilities in the SPP models.
- STEP PID 31033: upgrade the Berthold to Southwest Minot 115kV transmission line in the MISO 21SLL and 26SUM models based on the data for these facilities in the SPP models.

Although these planned TEP projects were added to the study models, the purpose of this study did not include proposing transmission upgrades, new transmission lines, or providing estimated costs of a transmission build-out.

3.2 Steady-State Transmission Analysis

For each of the five power flow models developed, PSE performed a PSS/E AC Contingency Calculation (ACCC) and a PSS®MUST Transmission Interchange Limits Calculation (TLTG) analysis on the North Dakota system to compare the flows and loadings on all bulk electric transmission facilities. These analyses focused on the North Dakota Export (NDEX), which has historically provided a benchmark for voltage stability in the region.

3.2.1 North Dakota Export Limit

Several North Dakota tie line transmission lines, including the NDEX facilities[3] (see Table C-9), were monitored under system intact conditions in order to compare the potential available capacity in each model. Although NDEX is a stability interface generally monitored for voltage stability, we used its definition as a way to monitor power flow on familiar North Dakota transmission facilities to demonstrate any trends. In Figure 3-3 below, NDEX totals approximately 60% - 70% of the established stability rating in the near term and five-year out models. However, once the load and generation growth assumptions are applied for the 38SUM model, we see that NDEX

[3] NDEX Facilities as defined in SPP's Flowgate report as of August 15, 2019, https://www.oasis.oati.com/SWPP/index.html

increases to 132.7% of the currently established summer peak stability rating. The excessive flow on this stability limit indicates that significant voltage instability could be observed and new transmission facilities would be required to accommodate the addition of new generation.

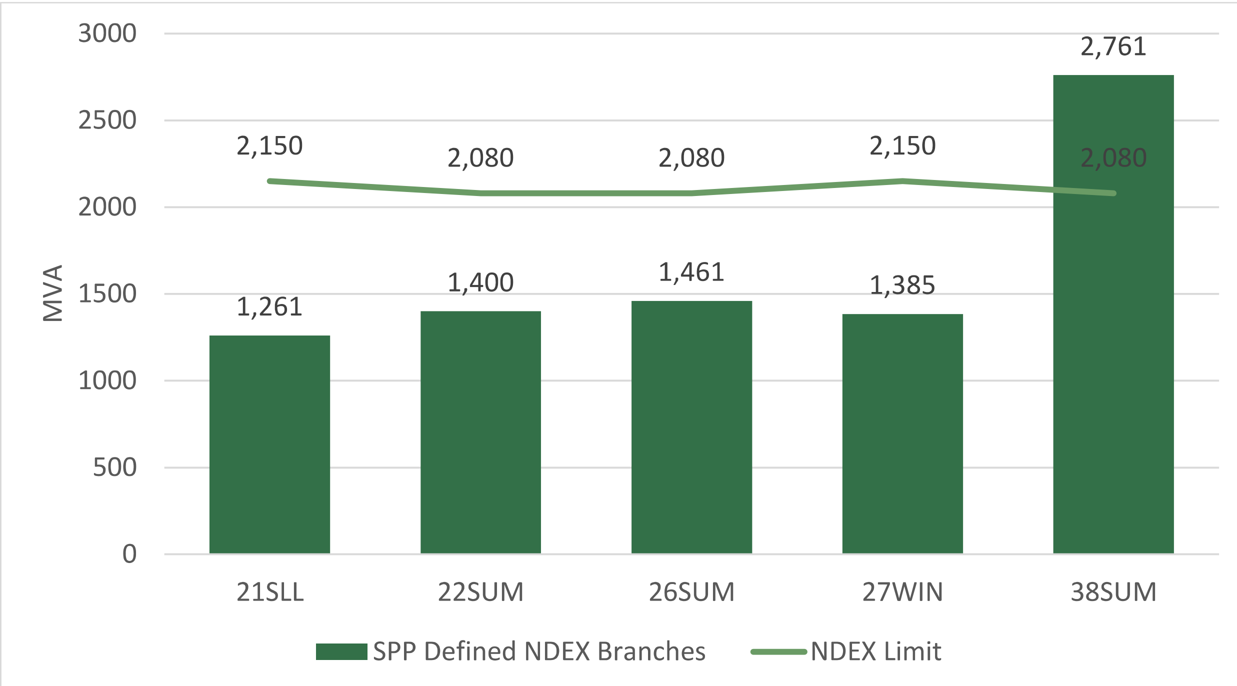

Figure 3-3: NDEX Tie Line MVA Flow Totals

Basin Electric Power Cooperative (BEPC) provided a list of facilities (see Table C-10) that define the North Dakota tie lines. We used this set of tie lines as another way to monitor power flow on North Dakota transmission facilities to demonstrate any trends. The total MVA flow of these facilities under system intact conditions in the summer peak study models are illustrated in Figure 3-4.

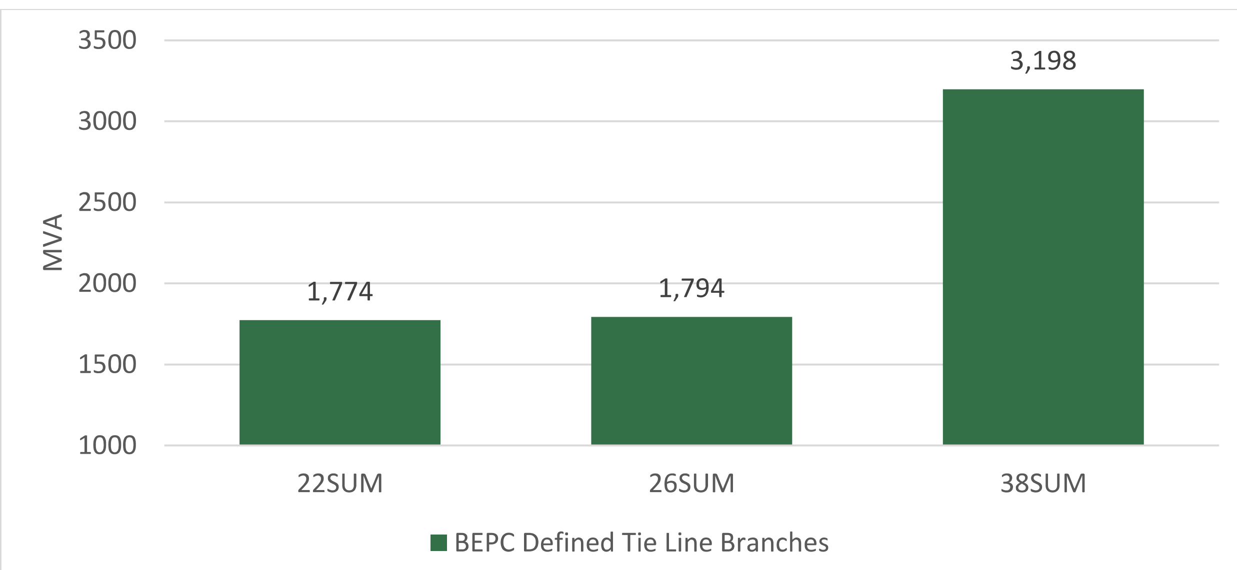

Figure 3-4: BEPC North Dakota Tie Line Flows

In addition, BEPC also provided a list of the Williston Load Pocket tie lines (see Table C-11). The total MVA flow of these facilities for system intact conditions in the summer peak study models are illustrated in Figure 3-5.

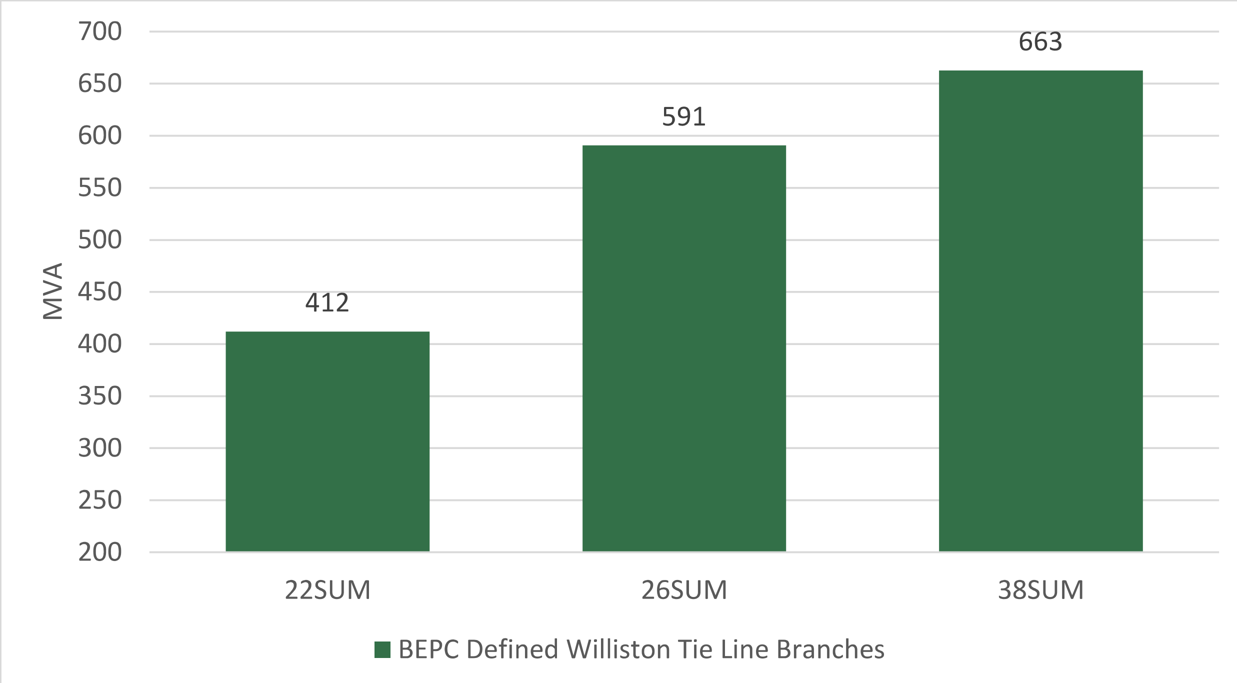

Figure 3-5: BEPC Williston Load Pocket Tie Line Flows

The increased power flows on the North Dakota tie lines and Williston Load Pocket tie lines are another indication that transmission capacity will be exhausted by new generation additions and contribute to additional curtailment, lower LMPs, or both without the investment in additional transmission capacity in North Dakota.

3.2.2 Available Transmission Capacity

PSE also performed a PSS®MUST transfer limit analysis to determine the amount of transfer capacity that could be available in each of the study models under system intact conditions prior to NDEX exceeding its established limits. The estimated available capacity is provided in Table 3-4.

Table 3-4: NDEX Available Generation MW Injection Capacity

Monitored Element	Contingency	21SLL	22SUM	26SUM	27WIN	38SUM
NDEX	Base Case	1323.3	1898.4	1811.3	2626.9	(429.2)

The results of the transfer limit analysis demonstrate the limited capability of exporting North Dakota generation to the MISO and SPP capacity and energy markets. We see limited injection capacity reported in the near-term 21SLL model, where transfers are higher due to low local demand. In comparing the summer peak models, we see available injection capacity starting to fall between 2022 and 2026. By 2038, NDEX has negative injection capacity. This indicates the excess generation above serving the local North Dakota summer peak load has nowhere to go and would likely need to be curtailed to maintain voltage stability. The increase in generation curtailments and further depression of LMPs in North Dakota will continue without the addition of significant

EHV and HV AC and/or HVDC transmission lines between North Dakota and the MISO and SPP load centers.

In addition, the results of the 38SUM PSS/E ACCC analysis identified nearly 6,000 instances of thermal overloads on the North Dakota transmission system, as shown in Figure 3-6.

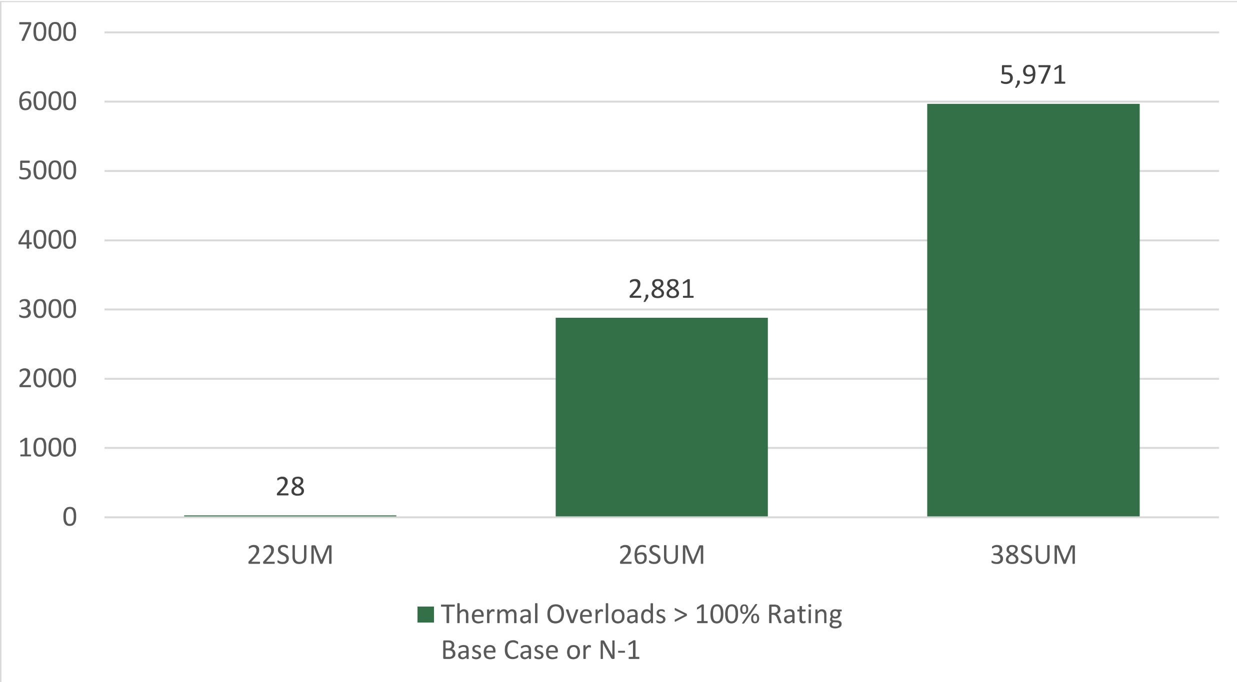

Figure 3-6: Count of Thermal Violations

As expected, the near-term 22SUM model demonstrates a relatively healthy steady-state transmission system in North Dakota. As generation and load increase from the 22SUM to 26SUM, the number of instances of thermal overload violations increases one hundred-fold from 28 to 2,881. Continued increases in generation and load in the 38SUM model beyond the normal transmission expansion planning period demonstrates another doubling of the number of thermal overload violations observed under system intact and N-1 contingency scenarios. With few planned transmission upgrades, these results demonstrate that more transmission capacity is needed to maintain a healthy transmission system in North Dakota.

To illustrate how the capacity in North Dakota decreases over time, PSE compared the thermal loading in the study models on the following 115kV, 230kV, and 345kV transmission lines that were reported as exceeding their limits in the 38SUM model.

- Buffalo – Jamestown 345kV
- Merricourt – Wishek 230kV
- Mound City – Glenham 230kV
- Heskett – Wishek 230kV
- Sheyenne – Audubon 230kV
- Stanton – Square Butte 230kV
- Barr Butte – Granora 115kV
- Barr Butte – Strandahl 115kV
- Beulah – Mandan 115kV
- Bismark Expressway – East Bismark 115kV
- Coyote – Westmoreland Portable 115kV

- Culbertson – Poplar 115kV
- Devils Lake SE – Sweetwater 115kV
- Dickinson Green River – Westmoreland Portable 115kV
- G8 – Patentgate 115kV
- Grand Forks – Falconer 115kV
- Grenora – Snake Butte 115kV
- Killdeer – Killdeer Pumping 115kV
- Langdon – Sweetwater 115kV
- Leeds – Penn 115kV
- Mont – Strandahl 115kV
- Oakdale – Killdeer 115kV
- Pioneer Station – Snake Butte 115kV
- Pleasant Lake – Leeds 115kV
- Pleasant Lake – Rugby 115kV
- Rugby Tap – Rugby 115kV
- Stanley – Tioga 115kV
- Stateline – Judson 115kV
- Stateline – Mont 115kV
- Stateline – Pioneer Station 115kV
- Towner – Botno 115kV
- Williston – Mont 115kV

Figure 3-7 illustrates that approximately 32% of the capacity on these transmission lines is available in the near term (22SUM) study model. By 26SUM, the available capacity on these transmission lines drops to 10%. Then, in the 38SUM study model, the power flows on these lines exceed their rated capacity by approximately 17%.

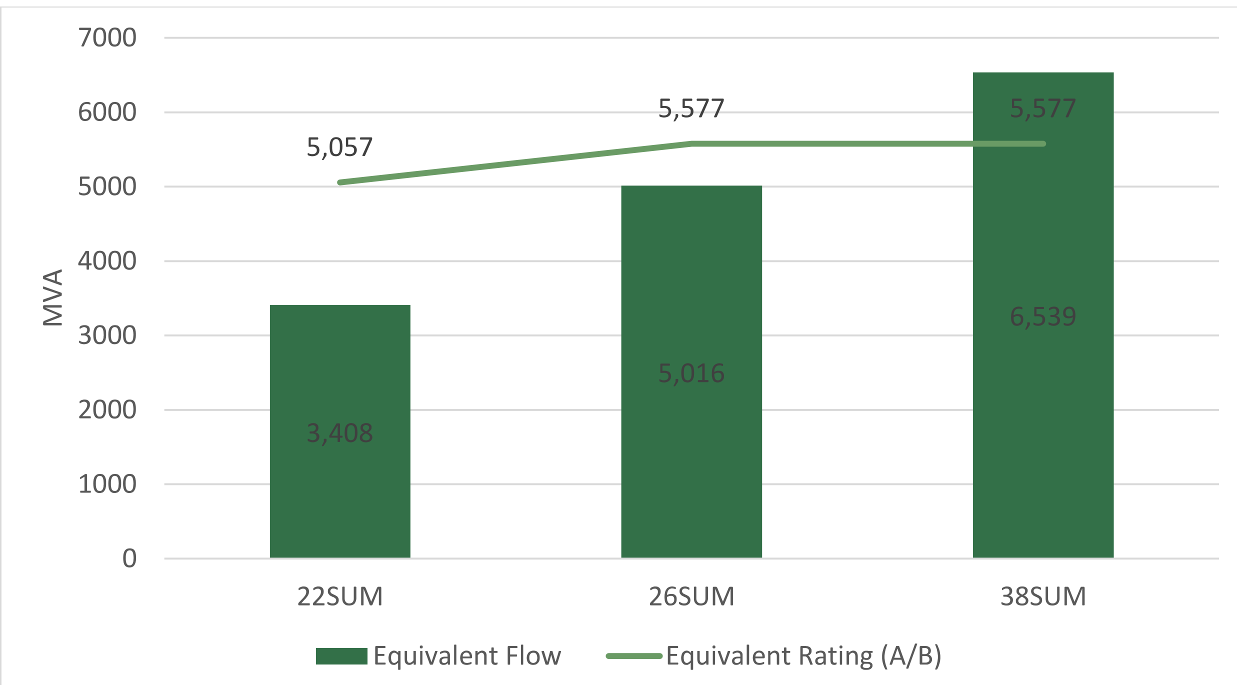

Figure 3-7: Select N-1 MVA Flow Totals

3.2.3 Steady-State Voltage Stability

In addition to monitoring thermal violations, PSE also monitored the system buses exceeding normal voltage operating criteria (0.95 per unit to 1.05 per unit). Figure 3-8 illustrates an increase in the number of potential voltage violations observed in the summer peak models.

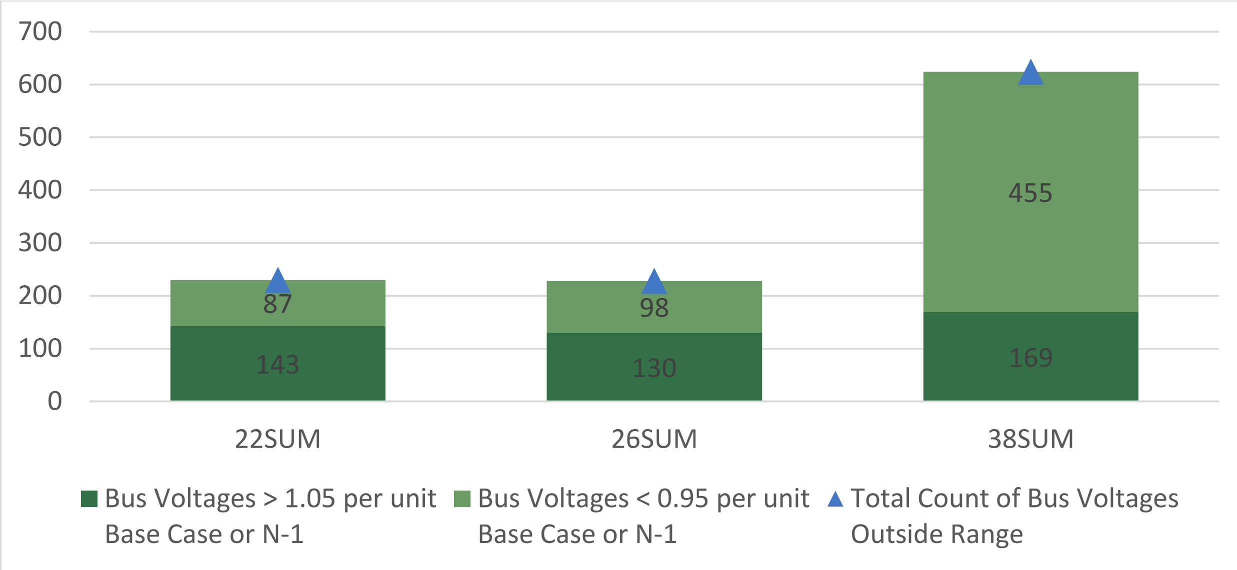

Figure 3-8: Count of Voltage Violations

This increase alludes to a decrease in voltage stability, especially in the 38SUM study model. Voltage criteria violations occur three times more frequently in the 38SUM study model than in the 22SUM or 26SUM study models. The analysis also has an increase in "blown cases", which are simulations not solving likely due to low voltages. While this points to voltage instability that could lead to cascading transmission system outages, our analysis was inconclusive with respect to voltage stability. Additional analysis outside the scope of this study would need to be performed on specific scenarios and system conditions in greater detail to quantify the limits of voltage instability in North Dakota or the NDEX stability flowgate.

3.3 LMP/Basis Historical Pricing Analysis

Historic pricing analysis provides a means to show the combined impacts of congestion and system losses. This analysis can provide an indicator of system adequacy using pricing as the metric. The historic information is available for all hours of the year and a wide range of physical locations. Pricing data can also provide a means of showing changes year over year during periods of changes in generation additions and transmission improvements.

The typical renewable energy expansion pattern is for as many renewable generation additions to be interconnected within the capacity of recent transmission improvements until the time when more major transmission improvements are needed for new renewable generation additions. The expectation in congestion and loss analysis is that the levels of congestion and losses on the system are increasing as shown by the pricing data until the point when more extensive transmission investments need to be made on the system. Year over year differences in pricing metrics can provide insights into which areas are more highly congested. Pricing metrics can also be helpful in comparing areas with higher and lower levels of renewable generation additions.

The Locational Marginal Pricing (LMP) is comprised of three components and is specific to each pricing node on the system. The Marginal Energy Component (MEC) is the same for all locations in the RTO and is defined as the marginal cost of energy based on all available generation on the system without regard to losses or congestion. The Marginal Loss Component (MLC) is defined as the pricing component demonstrating the impact of higher generation levels on the system losses. A positive MLC at a node indicates that an increased level of generation increases losses at that node. The Marginal Congestion Component (MCC) is defined as the pricing component showing the impact of system congestion for generation at a specific location. For a location with more generation available than transmission outlet capacity, the MCC is typically a negative value, driving down the price signal for generation located in that area on the system.

PSE evaluated a number of nodes in SPP and MISO in order to determine the historic levels of congestion and losses on the system. North Dakota has nodes in both SPP and MISO; pricing at nearby SPP and MISO nodes was also compared, as their pricing models are independent. Table 3-5 lists the SPP LMP nodes evaluated.

Table 3-5: SPP LMP Nodes

SPP Nodes	Description
Leland Olds	Key Generation node on 345kV system
Minot Wind	Wind Generation Node on lower voltage system
Pioneer	Western North Dakota oil load and location generation
SPP-GRE	SPP border to GRE in MISO
SPP-MDU	SPP border to MDU in MISO
Groton	Node south and east of Leland Olds on the 345kV system
Big Bend	Node south of Leland Olds in SPP on the 345kV system

Leland Olds is a key SPP node to evaluate because it is located in a region with a large amount of wind generation, and also demonstrates the pricing differences within the SPP, when compared with the Big Bend and Groton nodes. Coyote is a MISO pricing node that is in close electrical proximity to the LeLand Olds node and provides a location to compare the MISO and SPP pricing profiles.

The Minot wind node will show congestion and losses in an area that has some wind generation and is not located on the 345kV system. Pioneer is a key node to evaluate the congestion and losses in the western area of North Dakota that is not as likely to have wind generation and is located where the oil production has greatly impacted the energy and demand requirements with associated generation.

For the MISO nodes, Bison Wind is a key node near Leland Olds that allows an evaluation of congestion and losses in an area that has a fairly high level of wind generation. Langdon is also a node that was chosen to show the congestion and losses in the northeast region of the state. Ashtabula was chosen in order to evaluate congestion and losses in the east central area of the state. Coyote and the Otter Tail Power Company (OTP) Hoot Lake nodes were chosen in order to evaluate the MISO pricing differences (basis). Table 3-6 lists the pricing nodes evaluated in MISO.

Table 3-6: MISO Pricing Nodes

MISO Nodes	Description
Coyote	Key Generation node on 345kV system adjacent to Leland Olds
Hoot Lake	Node on 115kV system tied to North Dakota Export
Bison Wind	Wind Generation Node in central North Dakota
Oliver Wind	Wind Generation Node in central North Dakota
Langdon Wind	Wind Generation Node in northeast North Dakota
Ashtabula Wind	Wind Generation Node in east central North Dakota

Since there isn't a dataset for generation or load that is available to weight the pricing, this data is evaluated on a non-weighted basis. The combination of MLC and MCC is shown in many of the results, as this is the combined impact of the two components of the LMP that vary due to transmission system capabilities. Pricing data was evaluated monthly for the on-peak (7 am – 10 pm Monday – Friday) and off-peak periods. Trends for 2016 – 2019 were evaluated for SPP and MISO nodes, with additional 2011 – 2015 historical pricing data available for MISO nodes.

3.3.1 Nodal Average pricing results

Monthly on- and off-peak MLC + MCC (MLC/MCC) pricing was evaluated for all SPP and MISO nodes in order to compare and contrast the congestion and losses over time, and by location. The MLC/MCC pricing was first evaluated from year to year for a given month and period, and then compared to areas with varying levels of wind development. Monthly MLC/MCC bar charts for each of the SPP and MISO nodes are illustrated in Figure D-1 through Figure D-28.

Results show that there isn't a prevailing trend of pricing changes year over year across all 12 months. There are variations from year to year that are likely driven by shorter term changes on the system rather than permanent transmission additions or generation changes. In order to summarize the MLC/MCC in a meaningful way, an average value for the 2016 – 2019 period based on the monthly values has been compiled for SPP nodes in Table 3-7 and for MISO nodes in Table 3-8.

Table 3-7: SPP MLC/MCC 2016-2019 Average

Node	On-Peak $/MWHr	Off-Peak $/MWHr
LeLand Olds	(3.52)	(3.35)
Minot Wind	(2.21)	(2.03)
Pioneer	(0.97)	(0.72)
Big Bend	(4.44)	(3.58)
GRE MISO	0.64	0.69

Table 3-8: MISO MLC/MCC 2016-2019 Average

Node	On-Peak $/MWHr	Off-Peak $/MWHr
Bison	(8.10)	(6.12)
Oliver	(7.85)	(5.93)
Coyote	(8.07)	(6.02)
Langdon	(8.19)	(6.35)
Ashtabula	(5.99)	(4.88)
Hoot Lake	(4.88)	(3.75)

There is a unique opportunity to compare the Coyote and Leland Olds MLC/MCC, as these nodes are electrically very close to each other, but are in MISO and SPP, respectfully. MLC/MCC values for Coyote are quite a bit more negative than Leland Olds, which would normally indicate that the congestion and losses are more extreme at Coyote than at Leland Olds. This doesn't make sense from a system planning perspective, and upon further analysis which includes the full LMP pricing (which includes the MEC component of the LMP), the two nodes are quite similar. An important conclusion to note is that it is valid to compare nodes within an RTO when evaluating the amount of congestion and losses, as driven by higher levels of renewable generation, but not to compare nodes between RTOs.

Looking closer at the results for SPP nodes in North Dakota, it is clear that the nodes for Leland Olds and Minot are much more negative than the SPP Pioneer or the SPP GRE-MISO node, which is an indication of having a higher amount of wind generation relative to the transmission capability in each area. For the Leland Olds area, there is a more robust transmission system in the area, including 230kV lines interconnecting the Bison generation to the 345kV system. The Minot area has a lower voltage transmission system, but does not have as much wind generation as the area surrounding Leland Olds. This pricing analysis would indicate that for a similar congestion and losses profile, Minot and Leland Olds experience comparable loading.

For the MISO nodes, the level of MLC/MCC are very comparable for Bison and Langdon, but lower for Ashtabula. This could be an indication that there is more available transmission capacity in the east central area of North Dakota. The lower values for Hoot Lake provide an additional indication of an area that has less wind generation than other MISO nodes that were being evaluated.

Average MLC/MCC analysis doesn't provide insights into the combined impact of positive and negative values across a period, but a monthly duration curve does indicate the range of values across each month. The 2016 – 2019 monthly duration curves for Leland Olds are shown in Figure 3-9. Average MLC/MCC analysis doesn't provide insights into the combined impact of positive and negative values across a period for the month, but a monthly duration curve does indicate from a high level the range of values across each month. The 2016-2019 monthly duration curves for Leland Olds is shown in Figure 3-9, and it is clear that the range of values is very consistent for 2016 – 2018, while 2019 has a much more pronounced level of extremes, both positive and negative. These extremes were not enough to impact the averages but are an indication of short-term extreme conditions on the system. The correlation of these periods to binding constraint data can provide more insights into what is driving these excursions. Suffice it to say that the 2019 pricing was more unpredictable than 2016-2018.

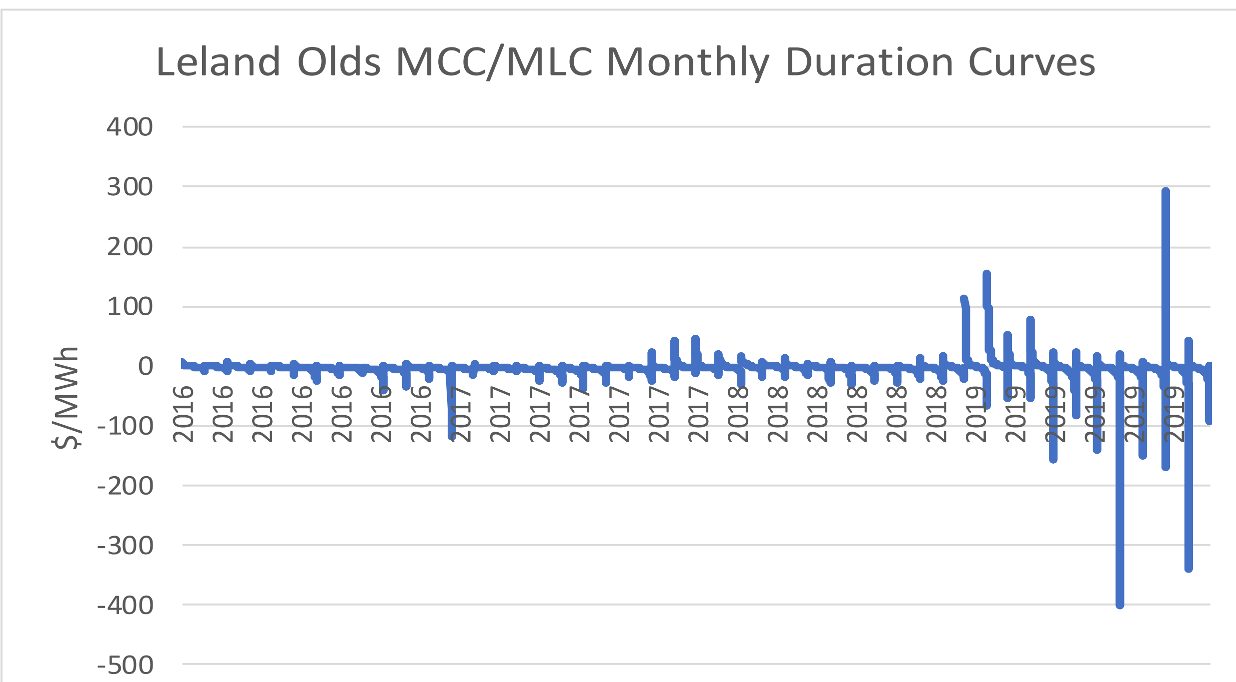

Figure 3-9: Leland Olds MCC/MLC Monthly Duration Curve

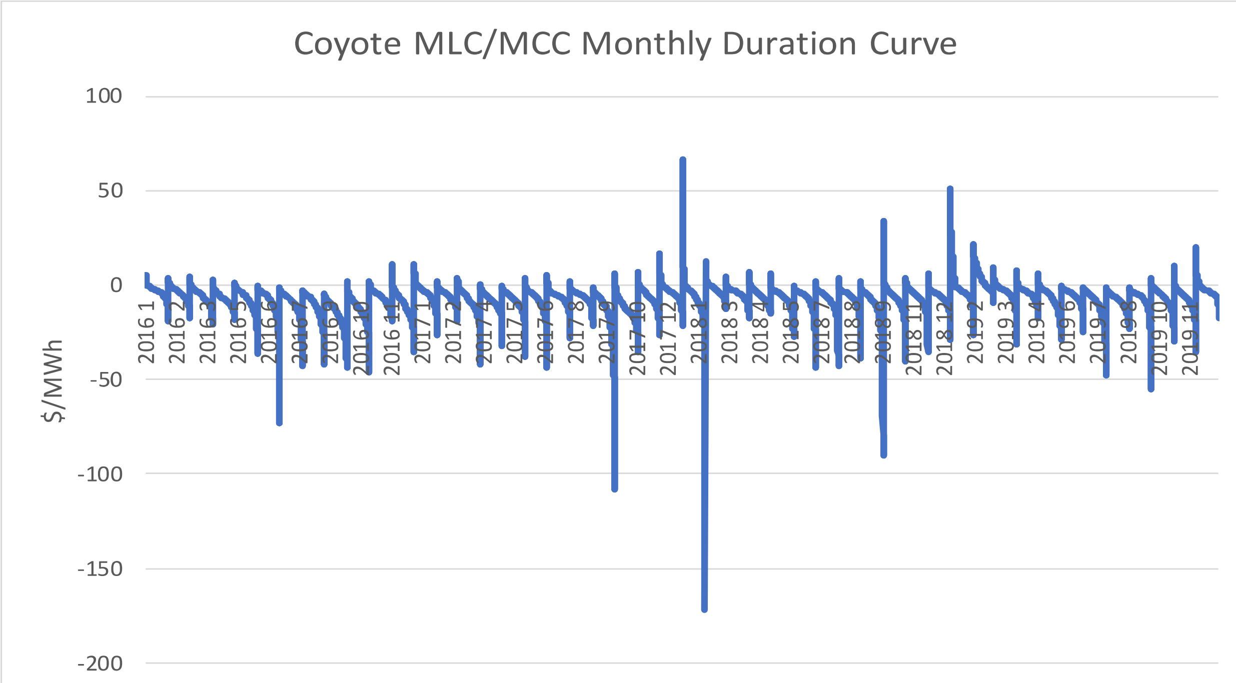

Figure 3-10: Coyote MLC/MCC Monthly Duration Curve

The monthly duration curve for the Coyote pricing node show a number of observations including a much more regular occurrence of negative values for all months from 2016 – 2019. There is a positive value for a number of months, but clearly for fewer hours than the hours with negative values. Another observation is that the more extreme range of values is not limited to 2019 but has a number of occurrences in 2017 and 2018, with less extreme variations in 2019.

3.3.2 Basis results

Basis is defined as the pricing difference between two points on the system. Basis analysis shows the value of power at different locations on the system. There are also trading hubs on the system where power is purchased and sold, allowing pricing at the trading hubs to be compared to pricing with other transactions from the same location. The basis from SPP Leland Olds to Big Bend and to Groton demonstrates the pricing basis over two major 345kV transmission lines from North Dakota. The MISO basis from Coyote to Hoot Lake provided a means of showing pricing differences on major North Dakota Export facilities.

Monthly basis results for the SPP and MISO paths are similar in that the highest levels of basis occur in the June – August timeframe, with lower values in other months. The SPP Leland Olds to Big Bend basis is slightly negative for all months except June and July, and more strongly positive in the off-peak months as seen in Figure 3-11. In the on-peak graph of Figure 3-12, the other months are more negative than June and July.

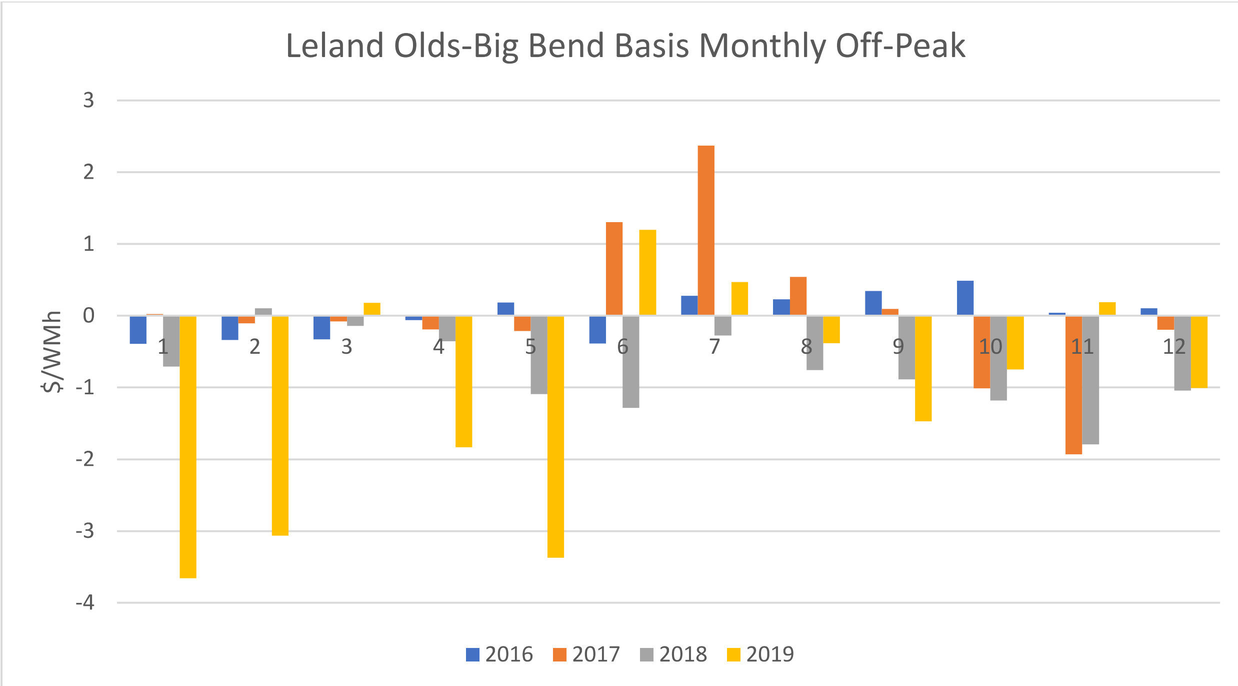

Figure 3-11: Leland Olds-Big Bend Basis Monthly Off-Peak

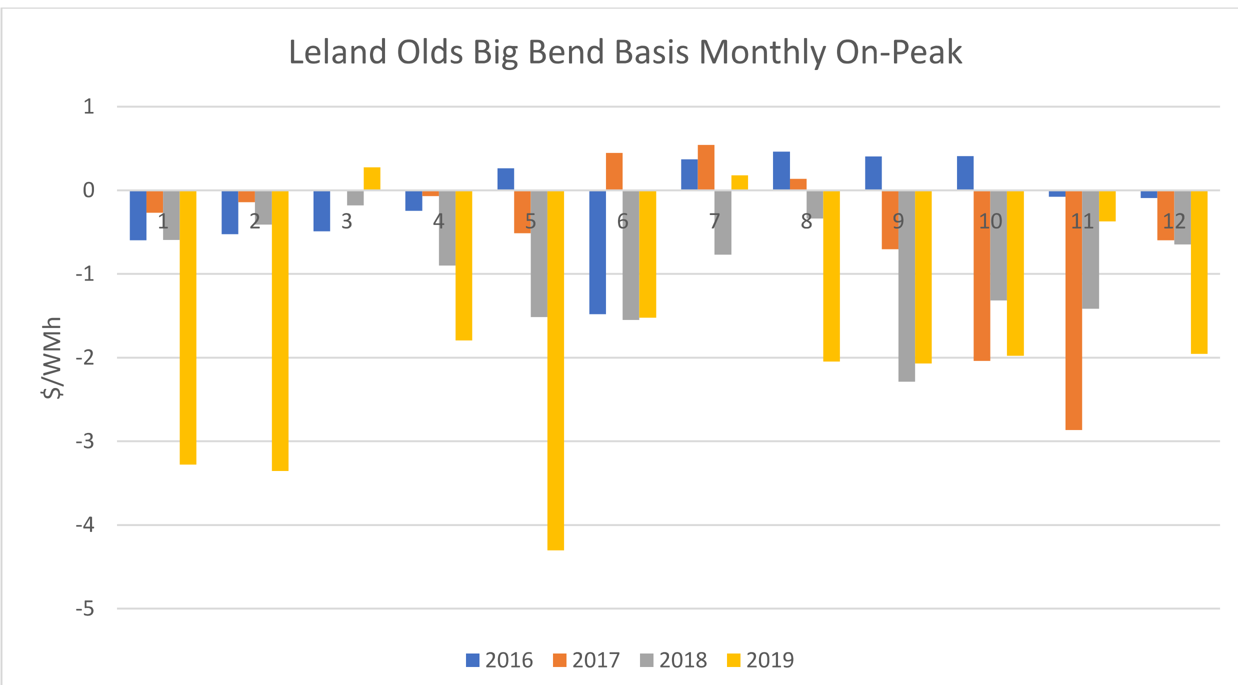

Figure 3-12: Leland Olds-Big Bend Basis Monthly On-Peak

The Leland Olds Groton basis results are positive June – August for both off-peak as shown in Figure 3-13 and on-peak periods as shown in Figure 3-14.

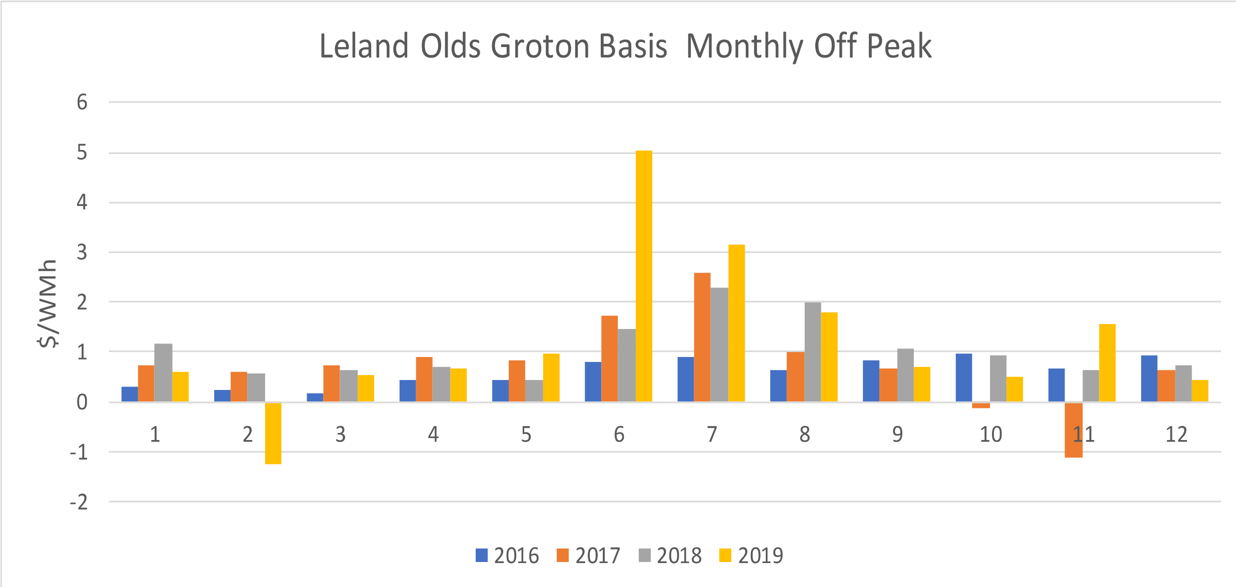

Figure 3-13: Leland Olds Groton SPP Basis Monthly Off-Peak

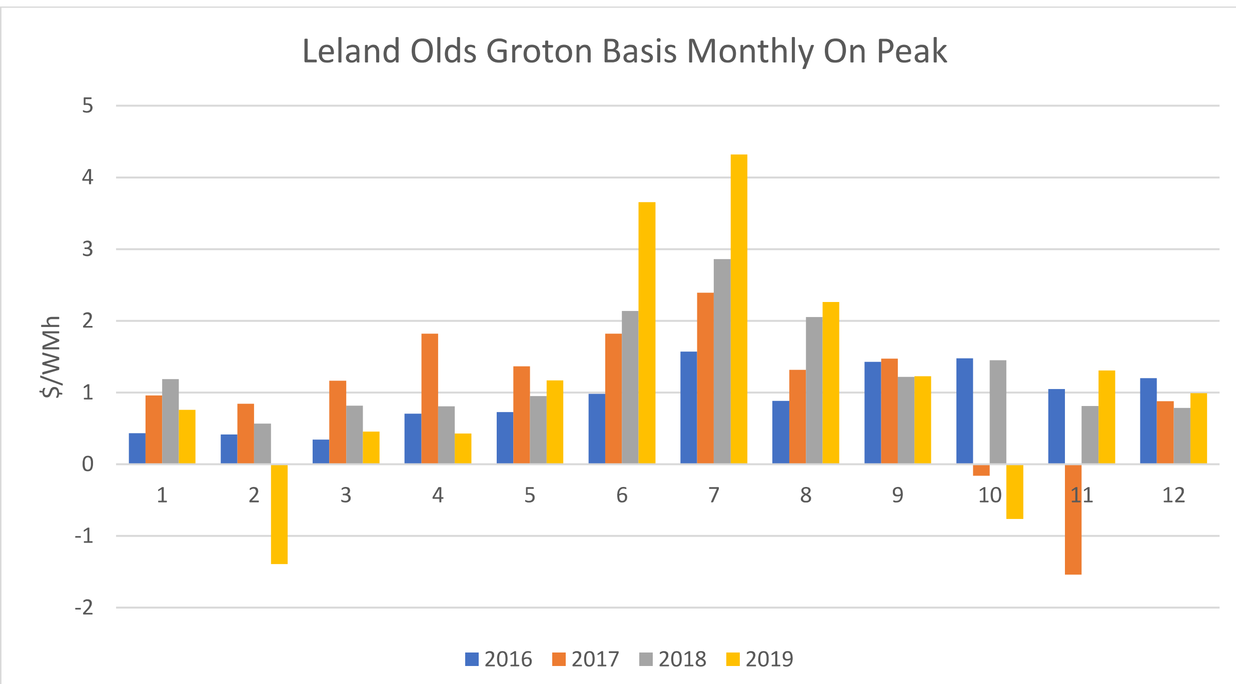

Figure 3-14: Leland Olds Groton SPP Basis Monthly On-Peak

MISO basis results for Coyote to Hoot Lake are also positive months in June – August for both on-peak and off-peak periods, with on-peak averages being much higher than the SPP basis results. Averages in July approach $14/MWh on-peak, and other months are in the range of $8/MWh as seen in Figure 3-15 and Figure 3-16.

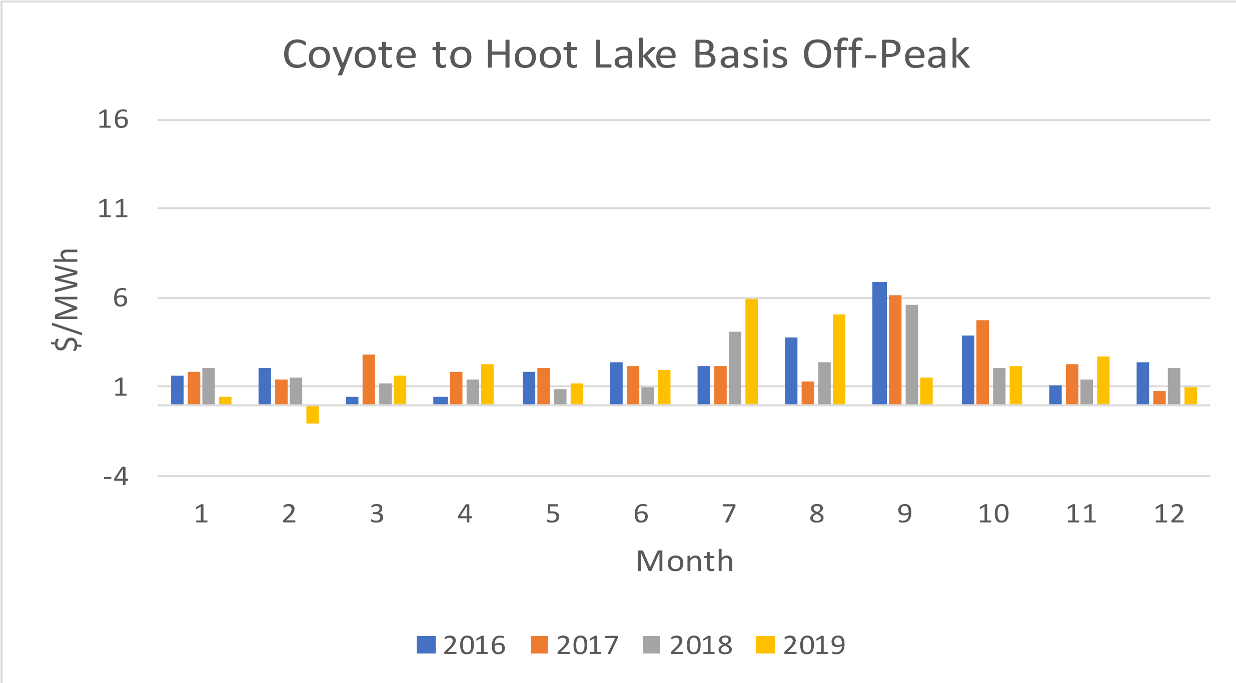

Figure 3-15: Coyote to Hoot Lake MISO Basis Off-Peak

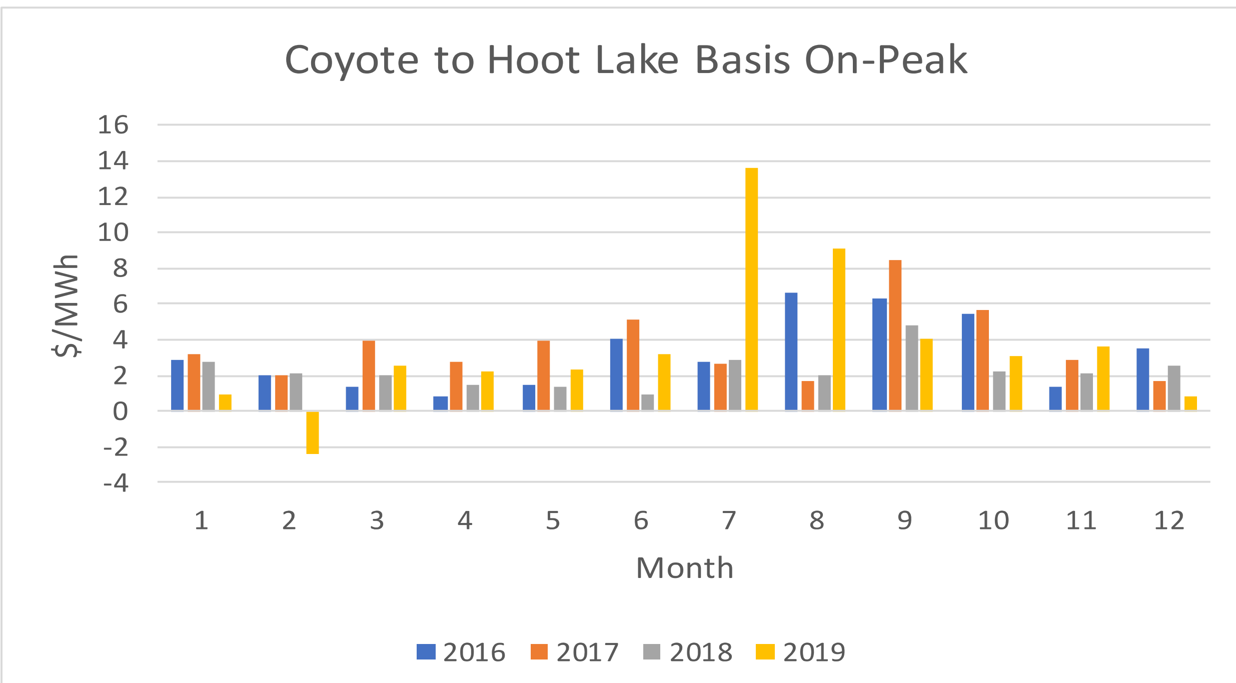

Figure 3-16: Coyote to Hoot Lake MISO Basis On-Peak

Monthly duration curves for the SPP and MISO basis also show a fairly unpredictable hourly distribution of the basis values, which provides a more complete picture of the range of positive and negative values by month. An example of this is shown for Coyote – Hoot Lake basis in Figure 3-17.

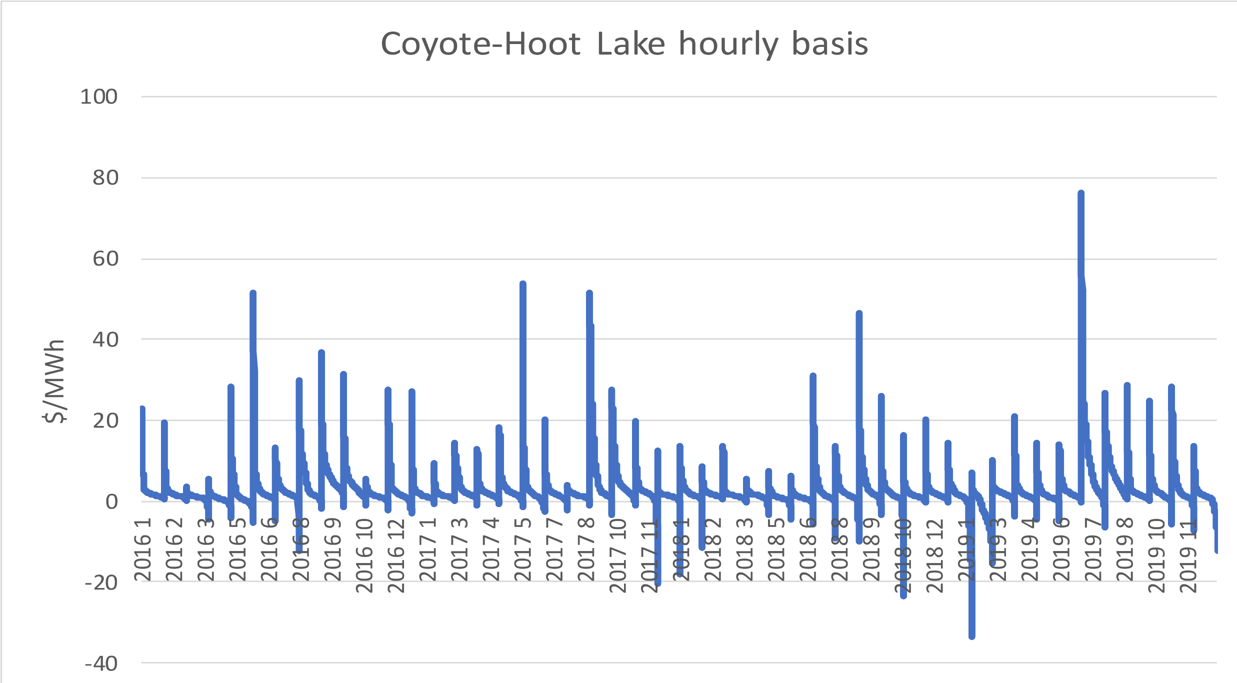

Figure 3-17: Coyote to Hoot Lake Hourly MISO Basis

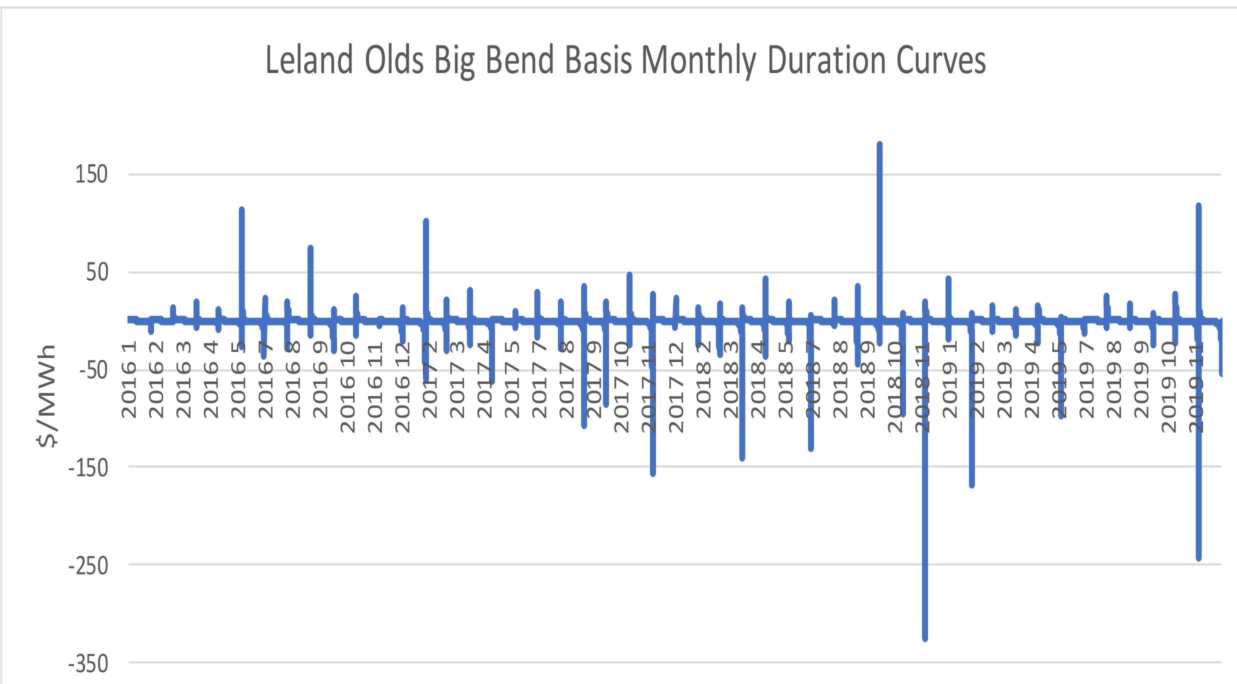

Figure 3-18: Leland Olds to Big Bend Hourly SPP Basis

Higher monthly results in June – August show greater levels of congestion in moving power out of North Dakota. The transmission results showing the need for additional transmission facilities for specific seasons can be compared to the basis pricing results to demonstrate that the greatest need is for the summer peak periods.

3.3.3 Electric Storage Considerations

Electric storage installations are likely to be an integral component of a higher renewable generation portfolio in the future. The implementation of electric storage in lieu of making traditional "poles and wires" transmission investments is being discussed in many arenas. Implementing storage in lieu of traditional transmission investments is still a relatively new concept, but there is value of including some preliminary analysis investigating the amount of electric storage required to accommodate the historic pattern of high renewable energy penetration. The analysis is supported by the premise that the current transmission system was adequate for the historic hourly pattern of electric generation and load. If a higher amount of renewable generation replaced a share of the conventional generation portfolio, electric storage could be the mechanism to store excess generation from renewables or provide energy back to the system when the renewable generation is not providing energy to match the historic energy production pattern from conventional resources.

This analysis looked at the number of hours of storage required to integrate higher levels of renewable resources and assumed that the historical dispatch and import/export levels and patterns did not change. This stringent condition was assumed in order to not impact other generation resources. This analysis also assumed that the energy storage added would be capable of charging and discharging over a much longer timeframe than typically required for energy storage in order to accommodate the higher levels of energy needed to serve summer load.

The available data for this analysis is not specific to North Dakota but is based on the MISO North region, and then scaled to the amount of annual North Dakota coal generation output. MISO has provided historic generation output data in MW by fuel type and region. The analysis provides insights into the amount of storage required at a system level without getting into the specific location of the interconnection.

Wind and energy storage were assumed to replace 30% of the existing coal generation based on the annual scaling of 2018 hourly production data for MISO North to the North Dakota totals. This results in a targeted annual amount of wind and energy storage of 5,600,000 MWh for the share of the MISO North hourly generation pattern that is assumed to be North Dakota coal generation. The energy storage system was assumed to be ideal, with no losses, in order to simplify the energy storage calculations. The model can be run in two modes: one was an annual energy storage optimization mode with the objective of matching the energy profile without regard to costs, and the other was a least cost approach where the assumed amount of wind was overbuilt. This approach would reduce the amount of energy storage systems required due to the higher costs of energy storage compared to wind generation investments.

Results of the first case demonstrate that 1,727 MW of wind additions would be required in order to provide the annual energy production of 5,600,000 MWh that would replace the theorical retirement of 900 MW of coal generation.

The hourly shape of the surplus and deficits with the additional 1,727 MW of wind is shown in Figure 3-19.

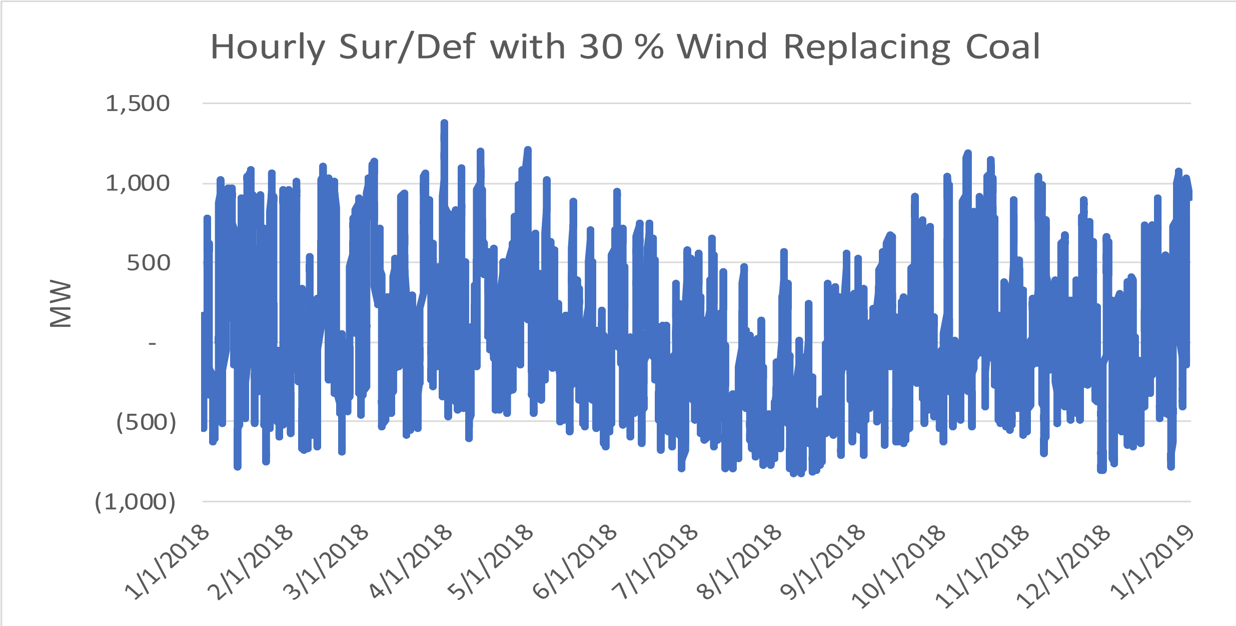

Figure 3-19: Hourly Surplus and Deficits: 30% Wind Replacement

In the hours above the zero line, the wind generation is higher than the coal generation that was replaced, and in the hours below the line, there isn't enough generation output from wind generation. This surplus and deficit can be accommodated by either changing the dispatch of other resources on the system after making the required transmission improvements, or by adding energy storage systems near the wind generation.

Another snapshot of the surplus and deficit results from the wind addition that shows the amount of electric storage is shown in Figure 3-20.

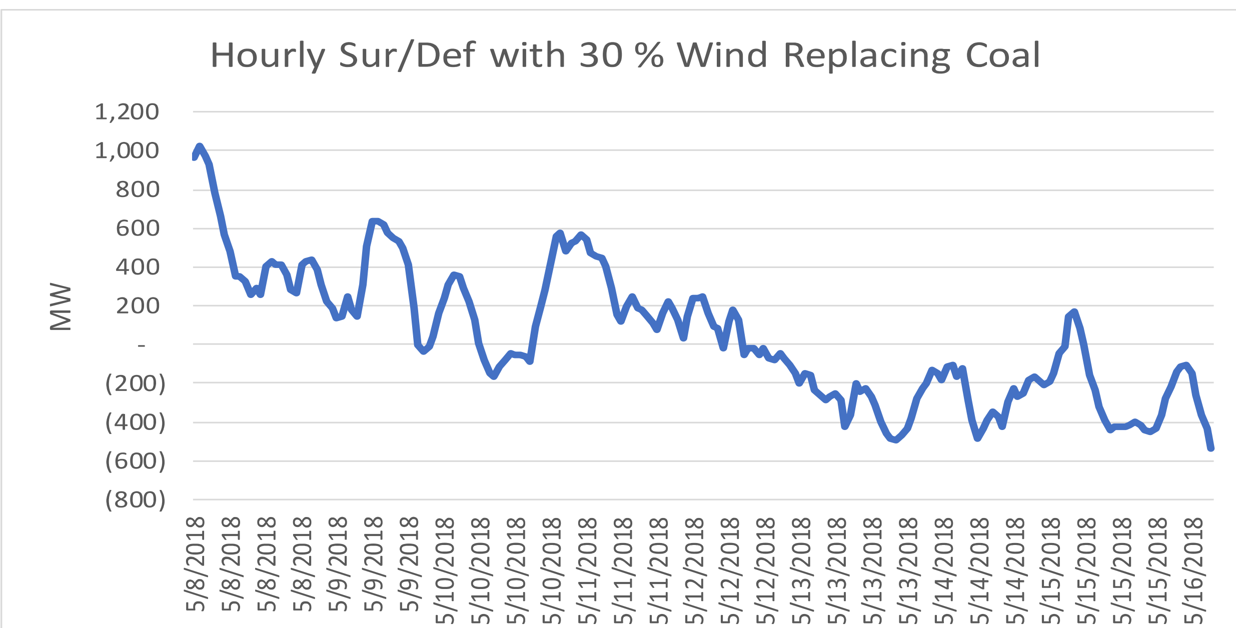

Figure 3-20: Hourly Surplus and Deficits: 30% Wind Replacement + Storage

This analysis shows the cumulative impact of the hourly surplus and deficit values. During the hours when the wind generation is above the zero line, the energy storage system is assumed to be charging. Hours below the zero line are when the energy storage system would be discharging onto the system.

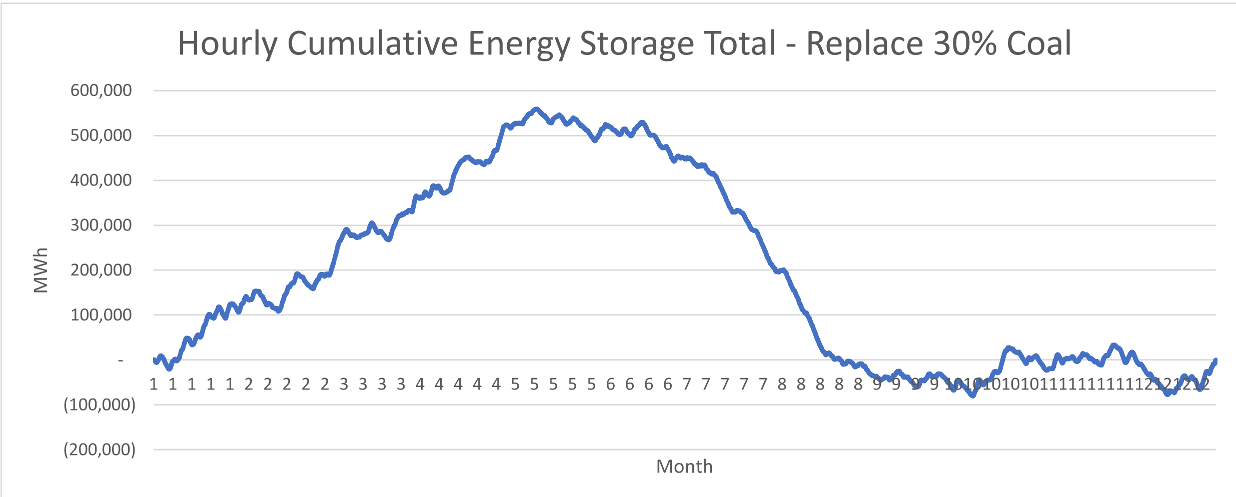

Figure 3-21: Hourly Cumulative Energy Storage Total

The energy storage required to make this amount of energy fit into the system dispatch would have a maximum charging capacity of over 831 MW, and a maximum discharge output of over 1,831 MW. Figure 3-21 shows the hourly cumulative energy storage required. The total amount of energy storage required on the system for the 2018 analysis was over 560,000 MWh. The amount of storage required could be much lower in a scenario of optimizing for lowest cost and overbuilding the wind generation. The minimum cost optimization was beyond the scope of this analysis but would be expected to significantly reduce the amount of energy storage required.

This analysis could be considered "locked down" in that it doesn't assume any additional import or export of power from outside the area of wind development that would require additional transmission facilities or changes in dispatch of other generation.

4 Conclusion

This study included a review of the applicable Generation Interconnection (GI) Queues and GI study reports and a review of the current Transmission Expansion Plans (TEPs) covering North Dakota. The research concluded that there is a significant amount of generation in the Midwest Independent System Operator (MISO) and Southwest Power Pool (SPP) GI Queues seeking interconnection in North Dakota during the study timeframe, and the amount of generation currently in these queues exceeds the projected load growth in North Dakota. With very few transmission expansion projects identified during the study timeframe that would add significantly to the transmission capacity for internal transfers and interstate exports, the existing North Dakota transmission system is becoming highly utilized with little excess capacity to accommodate any new generation being built in the state.

The study focused on three key analyses of North Dakota transmission capacity; steady-state thermal, steady-state voltage stability, and market signals. With the support of NDTA and several North Dakota Transmission Owners (TOs), PSE developed near-term, mid-term, and long-term transmission models to perform the steady-state assessments of the North Dakota transmission system capacity. In addition, PSE analyzed historical market data and trends to provide insight into how they may impact future pricing signals. The results of these analyses further confirmed the initial research; the North Dakota Transmission system is running out of available transmission capacity.

Recent GI requests in MISO and SPP have been generally unsuccessful, with about 80 percent of queue positions withdrawing during the GI study process. Most of these withdrawals are due to the multi-million-dollar network upgrades assigned to the generator projects during the MISO or SPP GI studies. These results are indicative of the need for additional transmission capacity in order to accommodate additional generation within the state of North Dakota.

Based on the assumptions included in our analyses, PSE believes that the excessive steady-state system intact flow observed on the NDEX facilities, the number of potential system intact thermal and voltage violations identified, and the indicated available injection capacity prior to contingencies indicate that system instability would likely be observed as North Dakota generation increases in the future. Mitigation would likely be required to accommodate the addition of new generation in North Dakota.

The Basis/LMP Pricing Analysis demonstrated that 2016-2019 MISO and SPP (MLC/MCC) values are negative in most locations of North Dakota. Monthly duration curves show increasing peaks and valleys in the $/MWHr pricing. The on-peak and off-peak basis comparisons of North Dakota generation nodes also show both positive and negative historical trends, although the magnitudes in either direction in $/MWHr is fairly minimal suggesting that there are no prime locations for generator additions based on Basis/LMP pricing signals alone.

The 30% wind replacement analysis demonstrates that approximately 1,727 MW of additional wind generation would be required in order to provide the annual energy production of 5,600,000 MWh needed to replace the theoretical retirement of 900 MW of coal generation. The energy storage required to make this amount of wind energy fit into the system dispatch would have a maximum charging capacity of over 831 MW, and a maximum discharge output of over 1,831 MW. The total amount of energy storage required on the system for the 2018 analysis was 560,000

MWh. The amount of storage required could be much lower in a scenario that optimized for lowest cost and overbuilding the wind generation; such an analysis was beyond the scope of this study.

The State of North Dakota's transmission system is nearing full utilization of its existing capacity. Without the addition of significant new extra-high voltage (EHV: 345kV – 765kV) and high voltage (HV: 100kV – 345kV) AC and/or HVDC transmission capacity in the next 10-20 years, we expect fewer and fewer new generation interconnection projects to be built, the risk of voltage instability within the region to increase, and LMP pricing for existing generation to continue to decrease as transmission congestion continues to increase for generation exports out of the state into the regional MISO and SPP markets.

Although this study was only designed to look at the existing and planned North Dakota transmission system, there are other study efforts underway looking at possible futures of significant renewable energy penetrations and robust transmission overlays, including North Dakota. One of these ongoing studies is the CapX2050 Transmission Vision Study[4].

[4] http://www.capx2020.com/

Appendix A. Generator Interconnection Queue Projects

Table A-1: MISO Generator Interconnection Projects

Proj. ID	TO	County	State	Service Type	POI Name	Summer MW	Winter MW	Fuel	Post GIA Status
G067	OTP	Cass	ND	ERIS	Unknown	2	2	Diesel	In-Service
G132	MDU	Dickey	ND	NRIS	Ellendale Sub 230kV	180	180	Wind	In-Service
G291	OTP	LaMoure	ND	ERIS	Jamestown - Oakes 41.6kV	19	19	Wind	In-Service
G380	OTP	Pierce	ND	ERIS	Rugby 115kV Substation	150	150	Wind	In-Service
G408	GRE	McHenry	ND	ERIS	McHenry - Souris 115kV	12	12	Wind	In-Service
G481	OTP	Rolette	ND	ERIS	Belcourt 69kV Substation	1	1	Wind	In-Service
G502	MP (Allete)	Oliver	ND	NRIS	Milton S Young Station #2 Switchyard Center Bus Substation	50	50	Wind	In-Service
G645	OTP	Stutsman	ND	NRIS	Ladish 115kV Substation	50	50	Coal	In-Service
G723	MDU	Morton	ND	ERIS	Glen Ullin	10	10	Diesel	In-Service
G752	MDU	Adams	ND	NRIS	Bison - Hettinger 230kV	150	150	Wind	In-Service
G788	OTP	Stutsman	ND	NRIS	Ladish 115kV substation	49	49	Coal	In-Service
G830	GRE	McHenry	ND	NRIS	GRE McHenry substation	99	99	Wind	In-Service
G876	GRE	McLean	ND	NRIS	GRE Coal Creek 230kV Substation	25	25	Coal	In-Service
G877	GRE	McLean	ND	NRIS	GRE Coal Creek 230kV Substation	40	40	Coal	In-Service
J003	MDU	Bowman	ND	NRIS	132N, 105W, Section 23 NE 1/4	20	20	Wind	In-Service
J110	MDU	Morton	ND	NRIS	MDU 41.6kV transmission line at Glen Ullin between switches 6315 and 6071	7.5	7.5	Biomass	In-Service
J200	MDU	Morton	ND	NRIS	RM Heskett Station 115kV & 41.6kV	75	99	Gas	In-Service
J249	MDU	Dickey	ND	NRIS Only	MDU Tatanka Substation	180	180	Wind	In-Service
J262	OTP	Stutsman	ND	NRIS	OTP Jamestown 345/115kV substation	100	100	Wind	In-Service
J263	OTP	Stutsman	ND	NRIS	OTP Jamestown 345/115kV Substation	100	100	Wind	In-Service
J290	NSP (Xcel)	Rolette	ND	NRIS	230kV Rugby to Glenboro	150	150	Wind	In-Service
J302	MDU	Emmons, Logan	ND	NRIS	230kV Heskett-Wishek	101.2	101.2	Wind	Active
J316	MDU	Dickey	ND	NRIS	MDU 230kV Tatanka-Ellendale line	150	150	Wind	Under Construction
J503	MDU	Emmons, Logan	ND	NRIS	230kV Heskett-Wishek, 20 miles NW of Wishek	98.8	98.8	Wind	Active
J580	MDU	Burleigh	ND	ERIS	Wishek to Heskett 230kV	298	298	Wind	Active

Proj. ID	TO	County	State	Service Type	POI Name	Summer MW	Winter MW	Fuel	Post GIA Status
J628	GRE	Grand Forks, Nelson	ND	NRIS	Ramsey - Prairie 230kV Line Tap	400	400	Wind	Active
J705	MP (Allete)	Morton	ND	NRIS	Tri-county 230kV substation	100	100	Wind	Active
J706	MP (Allete)	Morton	ND	NRIS	Tri-county 230kV sub	100	100	Wind	Active
J713	MP (Allete)	Oliver	ND	NRIS	Square Butte East 230kV Substation	300	300	Wind	Active
J741	MDU	Emmons, Logan	ND	NRIS	Wishek - Linton 115kV	51	51	Wind	Active
J743	NSP (Xcel)	Cass	ND	NRIS	Bison 345kV Substation	200	200	Wind	Active
J746	GRE	McHenry, McLean, Ward	ND	NRIS	Stanton-McHenry 230kV	200	200	Wind	Active
J779	MDU	Emmons, Logan	ND	NRIS	Bismarck-Linton 115kV	51	51	Wind	Active
J816	OTP	Cass	ND	NRIS	Buffalo 115kV Substation	60	60	Solar	Active
J880	NSP (Xcel)	Ward	ND	NRIS	Magic City 230kV sub	150	150	Wind	Active
J889	GRE	Nelson	ND	NRIS	Ramsey - Prairie 230KV Line Tap	150	150	Wind	Active
J897	GRE	Grand Forks	ND	NRIS	Prairie - Ramsey 230kV line	190	190	Wind	Active
J929	MDU	McIntosh	ND	NRIS	Wishek 41.6kV Substation	25	25	Solar	Active
J946	NSP (Xcel)	Cass	ND	NRIS	Bison 345kV Substation	200	200	Solar	Active
J975	OTP	Cass	ND	NRIS	Buffalo 115kV Substation	150	150	Wind	Active
J997	MDU	LaMoure	ND	NRIS	Ellendale 230kV Substation	200	200	Solar	Active
J1040	MDU	McIntosh	ND	NRIS	Wishek Junction 230kV Substation	250	250	Wind	Active
J1109	Xcel	Cass	ND	NRIS	Bison 345kV Substation	207	207	Wind	Active
J1170	Xcel	Cass	ND	NRIS	Bison 345kV Substation	200	200	Solar	Active
J1187	GRE	Mercer	ND	NRIS	Stanton 230kV Substation	151.8	151.8	Wind	Active
J1193	MDU	Morton	ND	NRIS	Heskitt 115kV Switchyard	103.1	103.1	Gas	Active
J1428	OTP	Cass	ND	NRIS	Buffalo 345kV Substation	200	200	Solar	Active
J1456	OTP	Sheridan	ND	NRIS	Harvey - Underwood 230kV Line Tap	300	300	Wind	Active

Table A-2: SPP Generator Interconnection Projects

GI Number	Nearest Town or County	State	CA	Summer MW	Winter MW	Service Type	Generation Type	Substation or Line	Status
GEN-2015-046	Williams	ND	WAPA	300	300	ER	Wind	Tande 345kV	Executed GIA
GEN-2015-096	Hettinger	ND	BEPC	150	150	ER	Wind	Brady 230kV substation	In-Service
GEN-2016-004	Oliver	ND	BEPC	202	202	ER/NR	Wind	Leland Olds 230kV	Active
GEN-2016-007	Barnes	ND	WAPA	100	100	ER	Wind	Valley City 115kV	Active
GEN-2016-052	Burleigh	ND	WAPA	3.3	3.3	ER	Wind	Hilken 230kV	Active
GEN-2016-053	Burleigh	ND	WAPA	3.3	3.3	ER	Wind	Hilken 230kV	Active
GEN-2016-130	Mercer	ND	WAPA	202	202	ER	Wind	Leland Olds 345kV	Active
GEN-2016-151	Burke	ND	WAPA	202	202	ER	Wind	Tande 345kV	Active
GEN-2016-155	Burleigh	ND	WAPA	1.3	1.3	ER	Wind	Hilken 230kV	Active
GEN-2017-010	Bowman	ND	BEPC	200.1	200.1	ER	Wind	Rhame 230kV Sub	Active
GEN-2017-048	Williams	ND	BEPC	300	300	ER	Wind	Tioga - Williston 230kV	Active
GEN-2017-214	Ward	ND		100	100	ER/NR	Wind	Logan 230kV station	Active
GEN-2017-215	Ward	ND		100	100	ER/NR	Wind	Logan 230kV station	Active
GEN-2017-216	Ward	ND		100	100	ER/NR	Wind	Logan 230kV station	Active
GEN-2017-235	Ward	ND		50	50	ER/NR	Wind	Berthold 115kV station	Active
GEN-2017-236	Ward	ND		50	50	ER/NR	Wind	Berthold 115kV station	Active
GEN-2018-008	McIntosh	ND		252	252	ER/NR	Wind	Groton-Leland Olds 345kV	Active
GEN-2018-010	Montrail	ND		74.1	74.1	ER/NR	Battery	Tande 345kV	Active
GEN-2018-039	LaMoure	ND		72	72	ER/NR	Solar	Edgeley 115kV substation	Active
GEN-2018-067	Williams	ND		255	255	ER	Wind	New switching station on Judson-Tande 345kV line	Active
GEN-2019-020	Williams	ND		35	35	ER/NR	Solar	Pioneer 115kV substation	Active
GEN-2019-037	Mercer	ND		150	150	ER/NR	Solar	BEPC 230kV substation	Active

Table A-3: MPC Generator Interconnection Projects

MPC Queue Position	Summer MW	Winter MW	Facility Type	Service Type	POI County, State	POI	Project Status
MPC00100	99.0	99.0	Wind	ER	Cavalier, ND	Langdon 115kV Substation	In-Service
MPC00200	60.0	60.0	Wind	ER	Cavalier, ND	Langdon 115kV Substation	In-Service
MPC00300	40.5	40.5	Wind	ER	Cavalier, ND	Langdon 115kV Substation	In-Service
MPC00500	378.8	378.8	Wind	NR	Cass, ND	Maple River 230kV Substation	In-Service
MPC01200	49.6	49.6	Wind	ER	Cass, ND	Maple River 230kV Substation	In-Service
MPC01300	455.0	455.0	Coal	NR	Oliver, ND	Square Butte 230kV Substation	In-Service
MPC02100	100.0	100.0	Wind	NR	Oliver, ND	Center - Mandan 230kV Line	In-Service
MPC03000	12.0	12.0	Solar	ER	Beltrami, MN	Bemidji 69kV Line (CB 550)	Active

MPC Queue Position	Summer MW	Winter MW	Facility Type	Service Type	POI County, State	POI	Project Status
MPC03600	200.0	200.0	Solar	NR	Richland, ND	Frontier-Wahpeton 230kV Line	Active
MPC03700	150.0	150.0	Solar	NR	Richland, ND	Frontier-Wahpeton 230kV Line	Active
MPC03800	250.0	250.0	Wind	NR	Eddy, ND Wells, ND	Center-Prairie 345kV Line	Active
MPC03900	151.2	151.2	Wind	NR	Eddy, ND Wells, ND	Center-Prairie 345kV Line	Active
MPC04000	300.0	300.0	Wind	NR	Oliver, ND Morton, ND	Square Butte 230kV Substation	Active
MPC04100	300.0	300.0	Wind	NR	Grand Forks, ND	Prairie 230kV	Active

Table A-4: Generator Interconnection Project Dispatch

					Dispatched MW				
GI Queue #	ISO/RTO	Requested MW	Fuel Type	In-Service Date	21SLL	22SUM	26SUM	27WIN	38SUM
GEN-2016-052	SPP	3.3	Wind	12/31/2016	0.6	0.1	0.1	0.2	0.2
GEN-2016-053	SPP	3.3	Wind	12/31/2016	0.6	0.1	0.1	0.2	0.2
GEN-2015-046	SPP	300	Wind	12/1/2017	54.0	9.4	9.4	18.0	30.7
GEN-2016-155	SPP	1.3	Wind	12/31/2017	0.2	0.0	0.0	0.1	0.1
GEN-2016-004	SPP	202	Wind	12/1/2018	36.4	6.3	6.3	12.1	11.3
GEN-2016-007	SPP	100	Wind	12/31/2018	18.0	3.1	3.1	6.0	5.6
J741	MISO	51	Wind	9/1/2019	9.2	1.6	1.6	3.1	2.2
J779	MISO	51	Wind	9/1/2019	9.2	1.6	1.6	3.1	2.2
J302	MISO	101.2	Wind	9/20/2019	18.2	3.2	3.2	6.1	4.4
J503	MISO	98.8	Wind	9/20/2019	17.8	3.1	3.1	5.9	4.3
GEN-2016-130	SPP	202	Wind	12/31/2019	36.4	6.3	6.3	12.1	11.3
GEN-2017-010	SPP	200.1	Wind	12/31/2019	36.0	6.2	6.2	12.0	11.2
GEN-2016-151	SPP	202	Wind	12/31/2019	36.4	6.3	6.3	12.1	20.7
J1187	MISO	151.8	Wind	5/1/2020	27.3	4.7	4.7	9.1	6.6
J580	MISO	298	Wind	6/30/2020	53.6	9.3	9.3	17.9	13.0
J705	MISO	100	Wind	7/1/2020	18.0	3.1	3.1	6.0	4.4
J706	MISO	100	Wind	7/1/2020	18.0	3.1	3.1	6.0	4.4
J946	MISO	200	Solar	7/31/2020	0.0	20.0	40.0	20.0	55.8
J743	MISO	200	Wind	7/31/2020	36.0	6.2	6.2	12.0	8.7
J997	MISO	200	Solar	9/1/2020	0.0	20.0	40.0	20.0	55.8
J628	MISO	400	Wind	9/15/2020	72.0	12.5	12.5	24.0	17.4
J889	MISO	150	Wind	9/15/2020	27.0	4.7	4.7	9.0	6.5
J880	MISO	150	Wind	9/15/2020	27.0	4.7	4.7	9.0	6.5
J713	MISO	300	Wind	9/15/2020	54.0	9.4	9.4	18.0	13.1
J816	MISO	60	Solar	9/15/2020	0.0	6.0	12.0	6.0	16.7
GEN-2018-067	SPP	255	Wind	10/30/2020	45.9	8.0	8.0	15.3	26.1

					Dispatched MW				
GI Queue #	**ISO/RTO**	**Requested MW**	**Fuel Type**	**In-Service Date**	**21SLL**	**22SUM**	**26SUM**	**27WIN**	**38SUM**
GEN-2017-235	SPP	50	Wind	12/1/2020	9.0	1.6	1.6	3.0	5.1
GEN-2017-236	SPP	50	Wind	12/1/2020	9.0	1.6	1.6	3.0	5.1
GEN-2017-214	SPP	100	Wind	12/1/2020	18.0	3.1	3.1	6.0	5.6
GEN-2017-215	SPP	100	Wind	12/1/2020	18.0	3.1	3.1	6.0	5.6
GEN-2017-216	SPP	100	Wind	12/1/2020	18.0	3.1	3.1	6.0	5.6
GEN-2017-048	SPP	300	Wind	12/1/2020	54.0	9.4	9.4	18.0	30.7
GEN-2018-039	SPP	72	Solar	12/31/2020	0.0	7.2	14.4	7.2	2.0
J929	MISO	25	Solar	6/30/2021	0.0	2.5	5.0	2.5	7.0
J1170	MISO	200	Solar	8/1/2021	0.0	20.0	40.0	20.0	55.8
J1109	MISO	207	Wind	8/1/2021	0.0	6.5	6.5	12.4	9.0
J1040	MISO	250	Wind	9/1/2021	0.0	7.8	7.8	15.0	10.9
GEN-2018-008	SPP	252	Wind	9/30/2021	0.0	7.9	7.9	15.1	14.1
J897	MISO	190	Wind	10/1/2021	0.0	5.9	5.9	11.4	8.3
J975	MISO	150	Wind	10/31/2021	0.0	4.7	4.7	9.0	6.5
GEN-2018-010	SPP	74.1	Battery	12/1/2021	0.0	14.8	14.8	14.8	37.9
MPC03600	MPC	200	Solar	12/31/2021	0.0	20.0	40.0	20.0	55.8
MPC03700	MPC	150	Solar	12/31/2021	0.0	15.0	30.0	15.0	41.9
J1428	MISO	200	Solar	8/1/2022	0.0	0.0	40.0	20.0	55.8
MPC03800	MPC	250	Wind	11/30/2022	0.0	0.0	7.8	15.0	10.9
MPC03900	MPC	151.2	Wind	11/30/2022	0.0	0.0	4.7	9.1	6.6
MPC04100	MPC	300	Wind	1/12/2023	0.0	0.0	9.4	18.0	13.1
MPC04000	MPC	300	Wind	1/12/2023	0.0	0.0	9.4	18.0	13.1
J1456	MISO	300	Wind	9/1/2023	0.0	0.0	9.4	18.0	13.1
J1193	MISO	103.1	Gas	10/1/2023	0.0	0.0	51.6	103.1	28.8
GEN-2019-037	SPP	150	Solar	12/1/2023	0.0	0.0	30.0	15.0	4.2
GEN-2019-020	SPP	35	Solar	12/1/2023	0.0	0.0	7.0	3.5	1.8

Table A-5: Existing Wind Dispatch

	Dispatched MW								
	21SLL		**22SUM**		**26SUM**		**27WIN**		**38SUM**
Generator Name	**Bench**	**Study**	**Bench**	**Study**	**Bench**	**Study**	**Bench**	**Study**	**Study**
Velva Wind	10.69	10.54	1.85	1.85	1.85	1.85	3.56	3.54	9.54
Courtenay Wind I	0.00	0.00	15.60	15.60	15.60	15.56	60.00	59.68	80.28
Courtenay Wind II	0.00	0.00	15.60	15.60	15.60	15.56	60.00	59.68	80.28
Lake Agassiz Wind	1.80	1.80	0.31	0.31	0.31	0.31	0.60	0.60	1.61
Oliver Wind I	45.54	44.88	7.89	7.89	7.89	7.87	15.18	15.10	40.62

	Dispatched MW								
	21SLL		22SUM		26SUM		27WIN		38SUM
Generator Name	**Bench**	**Study**	**Bench**	**Study**	**Bench**	**Study**	**Bench**	**Study**	**Study**
Oliver Wind II	44.55	43.91	7.72	7.72	7.72	7.70	14.85	14.77	39.74
Oliver Wind III	Not Modeled		0.00	0.00	Not Modeled		0.00	0.00	Not Modeled
Bison Wind 1A	33.12	32.64	5.74	5.74	5.74	5.73	11.04	10.98	29.54
Bison Wind 1B	40.59	40.00	7.04	7.04	7.04	7.02	13.53	13.46	36.20
Bison Wind 2	94.50	93.13	16.38	16.38	16.38	16.34	31.50	31.33	84.29
Bison Wind 3	94.50	93.13	16.38	16.38	16.38	16.34	31.50	31.33	84.29
Bison Wind 4	92.16	90.83	15.97	15.97	15.97	15.94	30.72	30.56	82.20
Bison Wind 5A	40.32	39.74	6.99	6.99	6.99	6.97	13.44	13.37	35.96
Bison Wind 5B	51.84	51.09	8.99	8.99	8.99	8.96	17.28	17.19	46.24
Bison Wind 6	92.16	90.83	15.97	15.97	15.97	15.94	30.72	30.56	82.20
Ashtabula I	57.00	56.18	23.17	23.16	23.17	23.11	94.55	94.04	119.21
Ashtabula I	42.96	42.34	7.49	7.49	7.49	7.47	14.40	14.32	38.53
Ashtabula II	26.00	25.62	10.76	10.76	10.76	10.74	20.70	20.59	55.39
Ashtabula II	44.30	43.66	7.72	7.72	7.72	7.70	14.85	14.77	39.74
Ashtabula II	45.90	45.24	7.96	7.96	7.96	7.94	15.30	15.22	40.94
Ashtabula III	55.80	54.99	9.73	9.73	9.73	9.71	18.72	18.62	50.09
Edgeley Wind	18.90	18.63	3.28	3.28	3.28	3.27	6.30	6.27	16.86
Herd Lake Wind I	40.00	39.42	6.24	6.24	6.24	6.23	12.00	11.94	32.11
Herd Lake Wind II	0.00	0.00	1.97	1.97	1.97	1.96	3.78	3.76	10.11
Herd Lake Wind III	0.00	0.00	4.59	4.59	4.59	4.58	8.82	8.77	23.60
Herd Lake Wind IV	0.00	0.00	10.48	10.48	10.48	10.46	20.16	20.05	53.95
Langdon Wind I	5.85	5.77	3.04	3.04	3.04	3.03	5.85	5.82	15.65
Langdon Wind I	38.00	37.45	15.44	15.44	15.44	15.41	70.00	69.62	79.47
Langdon Wind II	16.00	15.77	6.32	6.32	6.32	6.30	12.15	12.08	32.51
Langdon Wind II	12.15	11.97	6.32	6.32	6.32	6.30	12.15	12.08	32.51
Moorhead Wind	1.40	1.38	0.10	0.10	0.20	0.20	0.10	0.10	1.03
North Dakota Prairie Wind	42.90	42.28	24.52	24.51	24.50	24.44	42.91	42.68	115.50
Wilton Wind I	17.30	17.05	9.90	9.90	9.90	9.88	17.32	17.23	49.50
Wilton Wind II	17.30	17.05	9.90	9.90	9.90	9.88	17.32	17.23	49.50
Wilton Wind III	35.00	34.49	20.00	20.00	20.00	19.95	35.00	34.81	100.00
Pomona Wind	14.00	13.80	8.00	8.00	8.00	7.98	14.00	13.92	40.50
North Dakota Sunflower Wind	37.10	36.56	21.20	21.20	21.20	21.15	37.10	36.90	106.50
Antelope Hills Wind	60.20	59.33	Not Modeled		34.40	34.32	Not Modeled		172.50
Campbell County Wind	34.30	33.80	19.60	19.60	19.60	19.55	34.30	34.11	99.00
Brady Wind	52.50	51.74	30.00	29.99	30.00	29.93	52.50	52.22	151.50

	Dispatched MW								
	21SLL		22SUM		26SUM		27WIN		38SUM
Generator Name	**Bench**	**Study**	**Bench**	**Study**	**Bench**	**Study**	**Bench**	**Study**	**Study**
Lindahl Wind	52.50	51.74	30.00	29.99	30.00	29.93	52.50	52.22	150.49
Diamond Willow Wind	9.00	8.87	7.00	7.00	4.68	4.67	9.00	8.95	24.08
Cedar Hills Wind	5.85	5.77	6.00	6.00	3.04	3.03	5.85	5.82	15.65
Thunder Spirit Wind I	32.25	31.78	24.00	24.00	16.77	16.73	55.00	54.70	86.30
Thunder Spirit Wind II	12.75	12.57	13.00	13.00	6.63	6.61	12.75	12.68	34.12
Merricourt Wind	Not Modeled		Not Modeled		0.00	0.00	Not Modeled		0.00
Tatanka Wind	99.00	97.57	42.00	42.00	28.08	28.01	104.00	103.44	144.50

Appendix B. Transmission Expansion Plan Projects

Table B-6: MISO MTEP19 Active Projects

Target Appendix	App ABC	TO Member System	Project Id	Project Description	System Need	Estimated Cost
A in MTEP19	B>A	MDU	15746	Rebuild Beulah-Mandan 115kV and build a new 115 segment to terminate at Coyote	Age and condition of existing Beulah-Mandan 115kV line. Add Coyote terminal to retire 115kV thermal RAS at Coyote.	$26,900,000.00
A in MTEP19	B>A	MDU	15747	Add 230/41.6kV transformer and 41.6 ring bus at Merricourt Substation. Build Merricourt-Ashley 41.6kV line and Merricourt-Fredonia 41.6kV line.	Low voltages on 41.6kV system for various contingencies	$12,100,000.00
A in MTEP19	B>A	MDU	15780	Build new Lignite-Kincaid 60kV line	Allows Kincaid 60kV switching station to be retired	$3,100,000.00
A in MTEP19	B>A	MDU	16124	New 115kV substation with distribution transformer on the Dickinson North-Dickinson West 115kV line	Load growth	$7,000,000.00
A in MTEP19	B>A	MPC	15666	Reroute Center-Square Butte 230kV and Center-Roughrider 230kV around the Young 1/2 (Center) plant, adding 0.4 miles to each line.	Reroute is required to provide access to the coal pile expansion and provide space for Project Tundra (new facilities at the plant).	$2,000,000.00
A in MTEP19	B>A	OTP	16146	New Substation delivery to the 41.6kV on the West side of Jamestown. The project will consist of - One 115kV Circuit Breaker and one 41.6kV Circuit Breaker and a 25 MVA transformer.	Improves reliability by introducing a new high voltage transmission source from a 115 to a 41.6kV transmission system.	$3,000,000.00
A in MTEP19	B>A	OTP	16485	This project consists of upgrades to Otter Tail Power Company's substations and transmission lines to accommodate the interconnection of two wind generators, J436 and J437, to the Big Stone South to Ellendale 345kV transmission line. Five Facility upgrades are needed: • Forman to Hankinson 230kV line • Forman substation • Forman to Oakes 230kV line • Oakes substation • Oakes to Ellendale 230kV line	Network Upgrades to the Transmission Owner's substations and transmission lines required for the interconnection of the Interconnection Customers' Projects J436 and J437.	$1,439,902.00

Target Appendix	App ABC	TO Member System	Project Id	Project Description	System Need	Estimated Cost
A in MTEP19	B>A	OTP	16924	This project consists of upgrades to Otter Tail Power Company's substations and transmission lines to accommodate the interconnection of a wind generator, J488, to the Big Stone South to Ellendale 345kV transmission line. Four Facility upgrades are needed: • Forman to Hankinson 230kV line • Forman substation • Forman to Oakes 230kV line • Oakes to Ellendale 230kV line	Network Upgrades to the Transmission Owner's substations and transmission lines required for the interconnection of the Interconnection Customers' Project J488.	$2,628,468.00
A in MTEP19	B>A	OTP	17005	This project consists of upgrades to Otter Tail Power Company's Hankinson to Wahpeton 230kV transmission line to accommodate the interconnection of wind generators, J460/J488/J493/J526.	Network Upgrades to the Transmission Owner's transmission line required for the interconnection of the Interconnection Customers' Project J460/J488/J493/J526.	$1,596,087.00
A in MTEP19	B>A	XEL	15723	Remove 6 of the 12, 40 MVAR fast switched cap banks at Prairie. Remove 5 of 6 fast switch controls from remaining 40 MVAR cap banks	Changing transmission system no longer requires the capacitors for voltage support. High voltage conditions occur with more than 6 cap banks on. CAPX Fargo project added support to remove the need for fast switching on 5 of 6 remaining cap banks. Unnecessary costs incurred by maintaining and replacing aging capacitor banks that are no longer needed.	$725,000.00
A in MTEP19	B>A	XEL	15737	Remove the 5, 40MVAR fast switched cap banks at Sheyenne.	CAPX Fargo project removed the need for these capacitor banks for voltage stability. Removes maintenance and replacement concerns for aging fast-switch cap banks.	$750,000.00
B in MTEP19	B	MDU	15784	Rebuild Zahl-Corinth 60kV line	Age and Condition	$1,700,000.00
B in MTEP19	B	MDU	15785	Rebuild Kenmare-Mohall 60kV line	Age & Condition. Low voltage on 60kV system for loss of Kenmare Substation-Kenmare West 60kV line.	$5,300,000.00
B in MTEP19	B	MDU	15787	Build new Kenmare 60kV substation	Age & condition of existing Kenmare 60kV bus and equipment. Improve reliability and operations by replacing old breaker bypass bus with ring bus.	$6,525,000.00

Target Appendix	App ABC	TO Member System	Project Id	Project Description	System Need	Estimated Cost
B in MTEP19	B	MDU	15788	Replace existing 41.6/69kV transformer with a new 115/69kV transformer. Build new 115kV ring bus to replace existing 115kV main & transfer bus.	New 115/69 transformer is need to support 69kV system out of Hettinger. The existing transformer is too small, 6 MVA, to provide support to Elgin for loss of any section of the Heskett-Devaul 69kV line. The short circuit strength on the 69kV when sourced from Hettinger is weak and makes relay coordination difficult. The new 115/69 transformer will improve short circuit strength and relaying. There are not any 115 bays available for expansion on the main & transfer bus, so new ring bus will be constructed.	$6,900,000.00
B in MTEP19	B	OTP	15728	New 41.6 cap bank (1x3 Mvar) will be installed at OTP's Abercrombie 41.6kV Substation.	Studies have shown due to existing load and load growth this 41.6kV cap bank are needed for voltage support.	$1,000,000.00
B in MTEP19	B	OTP	16284	Reconductor 7 miles with new 1/0RT2 conductor. Rest of the line will stay with 266R conductor.	Age and condition of 7 miles between Buffalo-Enderlin 115kV transmission line will be reconductored. Multi-year project being done for reliability.	$4,000,000.00
B in MTEP19	B	OTP	16285	Due to reliability OTP will reconductor 2 miles with new 1/0RT2 conductor.	Age and condition of 2 miles between Gackle to Streeter 41.6kV transmission line will be reconductored.	$600,000.00

Table B-7: MISO MTEP Appendix A Projects (Quarterly Status Report)

Target Appendix	TO Member System	Proj. ID	Facility Type	Description	Plan Status	MTEP18 Expected ISD	MTEP18 Estimated Cost
A in MTEP18	MDU	15184	BUS	Terminate Bowman 230kV line into new bay at Hettinger 230kV substation, add a new breaker and remove one old breaker	In-Service	8/31/2018	$815,032
A in MTEP12	GRE	11563	SUB	Install 115kV ring bus at McHenry 115/230kV substation.	In-Service	9/20/2018	$4,952,173
A in MTEP11	MDU	2220	TX	Ellendale Substation, Transformer 345/230, Line Reactor	In-Service	3/31/2019	$22,000,000
A in MTEP11	MDU, OTP	2220	LN	Big Stone South – Ellendale 345kV Line	In-Service	3/31/2019	$225,000,000
A in MTEP12	XEL	3797	LN	New 5 mile Maple River – Reed River 115kV line	Under Construction	5/31/2019	$13,900,000
A in MTEP12	XEL	3797	SUB	New Red River 115kV substation and Termination Work	Under Construction	5/31/2019	$3,800,000

Target Appendix	TO Member System	Proj. ID	Facility Type	Description	Plan Status	MTEP18 Expected ISD	MTEP18 Estimated Cost
A in MTEP12	XEL	3797	SUB	New Maple River 115kV substation and Termination Work	Under Construction	5/31/2019	$3,199,014
A in MTEP18	MDU	13869	SUB	115kV three breaker ring bus and 115/69kV transformer	Planned	12/31/2019	$4,720,000
A in MTEP18	MP	15144	CAP	Existing cap bank relocated from Bison to Square Butte East	Planned	8/24/2018	$150,000
A in MTEP18	OTP	15165	TX	New 10 MVA 115/12.5kV transformer	Planned	7/15/2018	$243,000
A in MTEP18	OTP	15165	SUB	Modifications to the Mapleton 115/41.6kV substation	Planned	7/15/2018	$955,700
A in MTEP17	MDU	12787	LINE	A radial 230kV line from WAPA Watford City to MDU Watford City	Planned	1/31/2018	$200,000
A in MTEP17	MDU	12787	SUB	A new 230/34.5kV substation with a 42 MVA 230/34.5kV transformer	Planned	6/30/2019	$3,300,000
A in MTEP17	XEL	12013	Dist	Install a third Distribution Transformer to accommodate increasing demand in the area	Planned	6/30/2019	$400,000
A in MTEP16	MDU	9120	LN	New Ellendale Jct-Leola Jct 115kV line	Planned	12/15/2018	$8,830,000
A in MTEP14	MDU	3083	CB	Complete North Dickinson bus	Planned	9/30/2019	$1,500,000
A in MTEP14	MDU	3083	LN	New line Segment	Planned	12/31/2017	$750,000
A in MTEP14	OTP	4444	LNup	Verify and remediate facilities as required due to the industry-wide NERC alert	Planned	12/31/2019	$7,701,028

Table B-8: SPP STEP 2019 Q1 Projects

PID	UID	Project Owner	Project Name	Upgrade Name	Current Cost Estimate
30943	51306	BEPC	Multi - AVS - Charlie Creek 345kV	AVS - Charlie Creek 345kV Ckt 2	$65,407,395
30943	51307	BEPC	Multi - AVS - Charlie Creek 345kV	AVS 345kV Substation	$6,121,210
30943	51308	BEPC	Multi - AVS - Charlie Creek 345kV	Charlie Creek 345kV Substation	$11,268,556
30944	51310	BEPC	Multi - Charlie Creek - Judson - Williston 345/230kV	Charlie Creek - Judson 345kV Ckt 1	$71,704,347
30944	51311	BEPC	Multi - Charlie Creek - Judson - Williston 345/230kV	Judson 345/230kV Substation	$24,758,086
30944	51312	BEPC	Multi - Charlie Creek - Judson - Williston 345/230kV	Judson - Williston 230kV Ckt 1	$3,159,903
30945	51314	BEPC	Multi - Judson - Tande - Neset 345/230kV	Judson - Tande 345kV Ckt 1	$66,207,772
30945	51315	BEPC	Multi - Judson - Tande - Neset 345/230kV	Tande 345/230kV Substation	$18,000,000
30945	51316	BEPC	Multi - Judson - Tande - Neset 345/230kV	Neset - Tande 230kV Ckt 1	$364,982
30945	51317	BEPC	Multi - Judson - Tande - Neset 345/230kV	Neset 230kV Terminal Upgrades	$4,000,000
31031	51503	BEPC	Multi - Kummer Ridge - Roundup 345kV New Line and Patent Gate and Roundup 345/115kV Substations	Roundup 345/115kV Transformer	$6,662,000
31031	51504	BEPC	Multi - Kummer Ridge - Roundup 345kV New Line and Patent Gate and Roundup 345/115kV Substations	Patent Gate 345/115kV Transformer	$6,662,000
31032	51506	BEPC	Multi - Plaza 115kV Substation and Blaisdell - Plaza 115kV New Line	Plaza 115kV Substation	$3,918,000
31032	51507	BEPC	Multi - Plaza 115kV Substation and Blaisdell - Plaza 115kV New Line	Blaisdell - Plaza 115kV New Line	$14,841,308

PID	UID	Project Owner	Project Name	Upgrade Name	Current Cost Estimate
31032	51508	BEPC	Multi - Plaza 115kV Substation and Blaisdell - Plaza 115kV New Line	Plaza 115kV Cap Bank	$283,000
31033	51509	BEPC	Line - Berthold - Southwest Minot 115kV Ckt 1 Reconductor	Berthold - Southwest Minot 115kV Ckt 1 Reconductor	$2,876,720
31031	51543	BEPC	Multi - Kummer Ridge - Roundup 345kV New Line and Patent Gate and Roundup 345/115kV Substations	Patent Gate 345kV Substation	$30,000,000
31031	51544	BEPC	Multi - Kummer Ridge - Roundup 345kV New Line and Patent Gate and Roundup 345/115kV Substations	Roundup 345kV Substation	$27,100,000
41200	61856	WAPA	Sub - Williston 115kV	Williston 115kV Terminal Upgrades	$5,000
41223	61894	CPEC	Line - New East Ruthville - SW Minot 115kV New Line	East Ruthville - SW Minot 115kV New Line	$20,746,000
41223	61895	CPEC	Line - New East Ruthville - SW Minot 115kV New Line	East Ruthville - SW Minot 115kV line Terminal Upgrades	$1,035,000
51278	72005	CPEC	Sub - Bismarck 115kV and North Bismarck 115kV Terminal Upgrades	North Bismarck 115kV Terminal Upgrades	$0
51278	72006	WAPA	Sub - Bismarck 115kV and North Bismarck 115kV Terminal Upgrades	Bismarck 115kV Terminal Upgrades	$90,000

Appendix C. Tie Line Facilities

Table C-9: SPP Defined NDEX Tie Lines

Alexandria - Riverview Rd 345kV
Audubon - Hubbard 230kV
Big Stone - Blair 230kV
Bison - Maurine 230kV
Broadland - Huron 230kV
Big Stone South - Brooking County 345kV
Canby - Granite Falls 115kV
Cass Lake - Zemple 230kV
Drayton - Letellier 230kV
Edgeley - Ordway 115kV
Ellendale - Aberdeen Junction 115kV
Forman - Summit 115kV
Forman - Roberts County 115kV
Hudson - Douglas County 115kV
Inman - Wing River 230kV
Kerkhoven - Kerkhoven Tap 115kV
LaPorte - Akeley 115kV
Leland Olds - Ft. Thompson 345kV
Leland Olds - Groton 345kV
Morris - Granite Falls 230kV
Rugby - Peace Garden 230kV
Rugby - Rollette 230kV
Sulley Butte - Oahe 230kV

Table C-10: BEPC Defined North DakotaTie Lines

Tioga - Boundary Dam 230kV
Larson - Boundary Dam 230kV
Drayton - Letellier 230kV
Rugby - Glenboro 230kV
Peace Garden - Glenboro 230kV
Peace Garden - Rolette 230kV
Glenboro - Glenboro Phase Shifter 230kV
Drayton - Donaldson 115kV
Bowesmont - Drayton Sugar 69kV
Grand Forks - Falconer 115kV
Prairie - Winger 230kV
Maple River - Winger 230kV
Sheyenne - Audubon 230kV
Moorhead - Morris 230kV
Alexandria - Bison 345kV
Wahpeton - Fergus Falls 230kV

Big Stone - Browns Valley 230kV
Roberts County - Summit 115kV
Ellendale - Big Stone South 345kV
Edgeley - Ordway 115kV
Ellendale - Aberdeen 115kV
Leland Olds - Fort Thompson 345kV
Leland Olds - Groton 345kV
Antelope Valley - Broadland 345kV
Sully Buttes - Oake 230kV
Sully Buttes 69/230kV Transformer
Bison - Maurine 230kV

Table C-11: BEPC Defined Williston Pocket Tie Lines

Tioga - Boundary Dam 230kV
Blaisdell - Logan 230kV
SW Minot - Berthold 115kV
Snake Creek - Garrison 115kV
Poplar - Wolf Point 115kV
Fairview - Richland 115kV
Charlie Creek - Patent Gate 345kV
Watford - Charlie Creek 230kV
Roundup - Kummer Ridge 345kV
Oakdale - Killdeer 345kV

Appendix D. Monthly On- and Off-Peak MLC/MCC

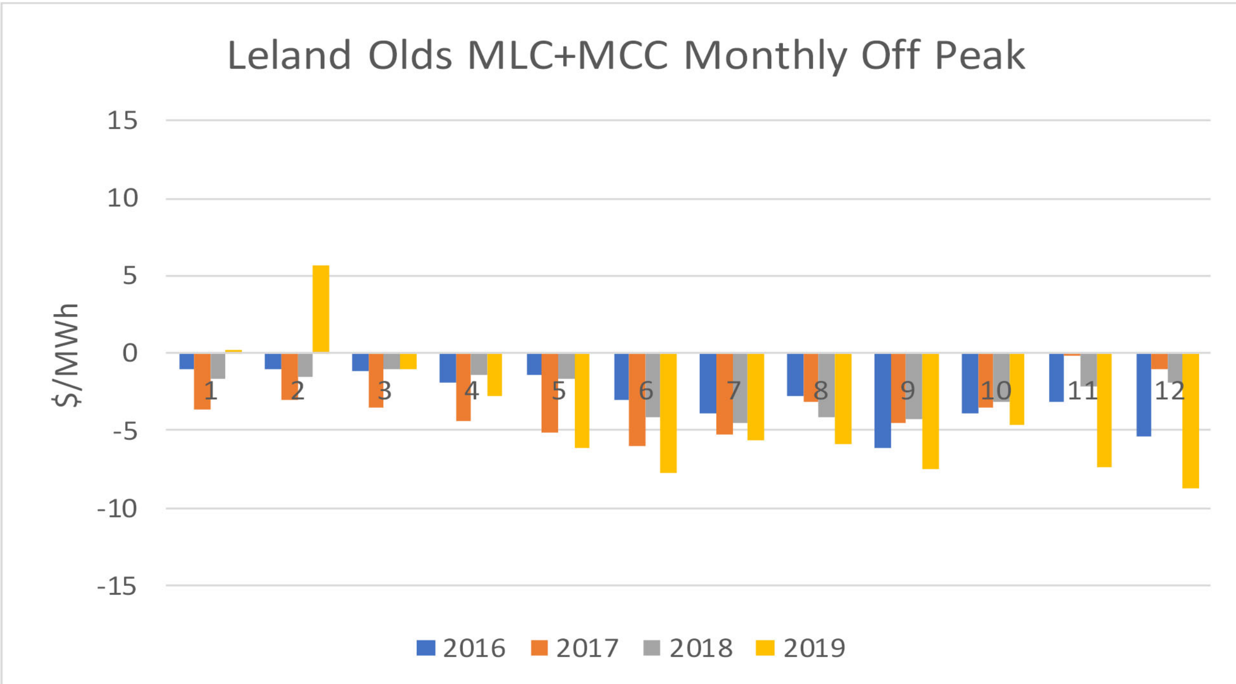

Figure D-1: Leland Olds MLC/MCC Monthly Off-Peak

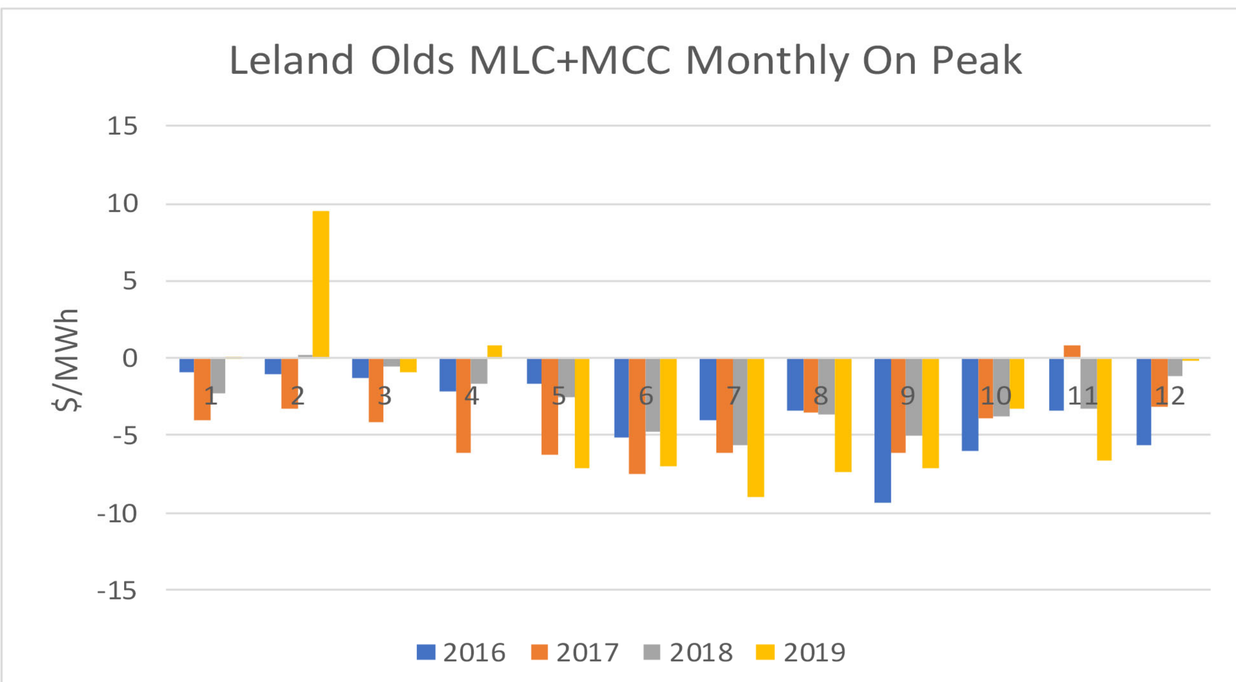

Figure D-2: Leland Olds MLC/MCC Monthly On-Peak

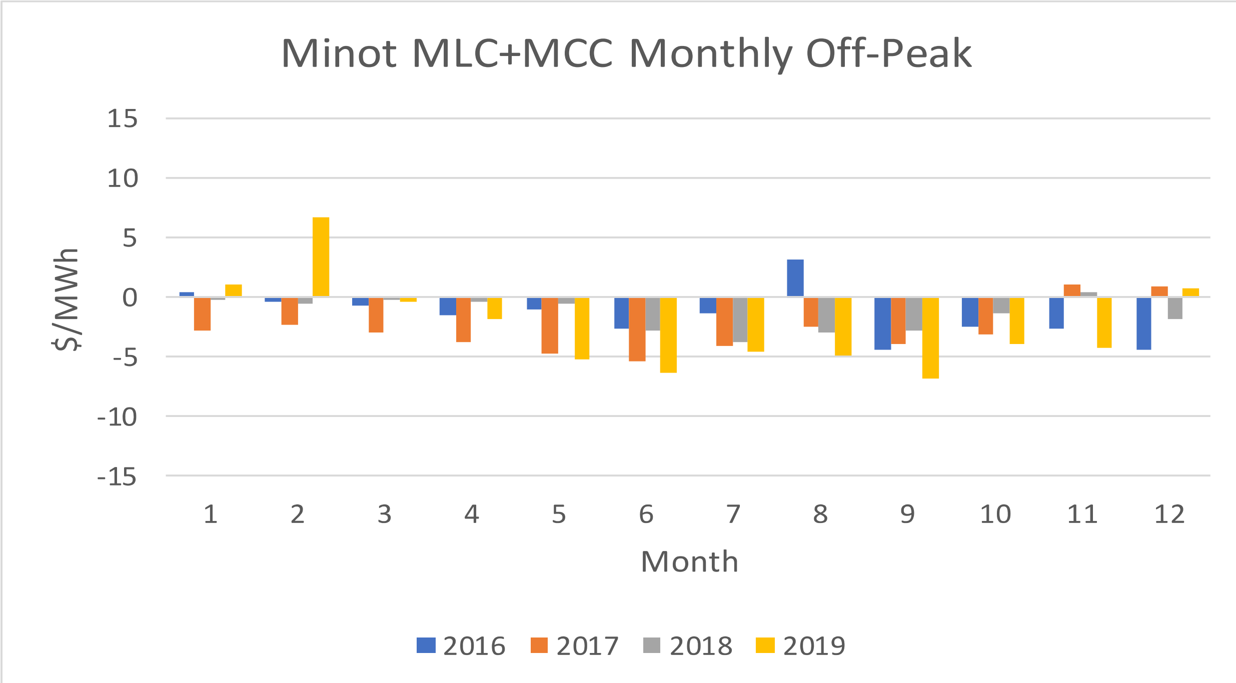

Figure D-3: Minot MLC/MCC Monthly Off-Peak

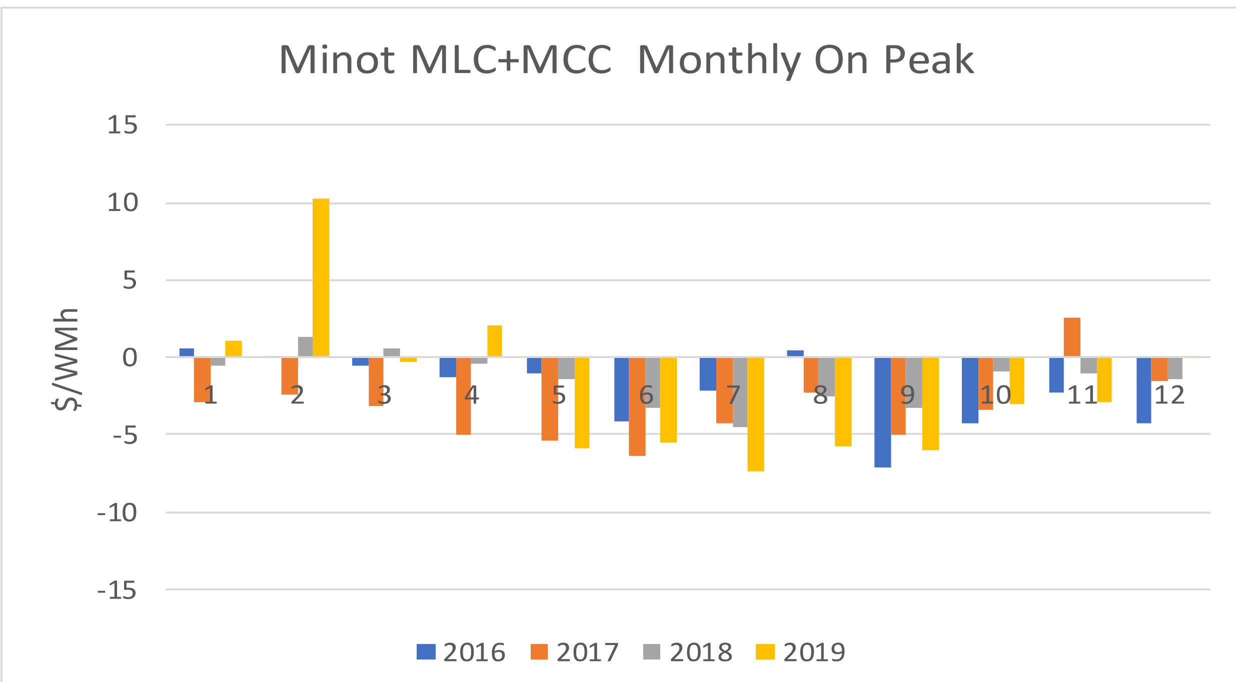

Figure D-4: Minot MLC/MCC Monthly On-Peak

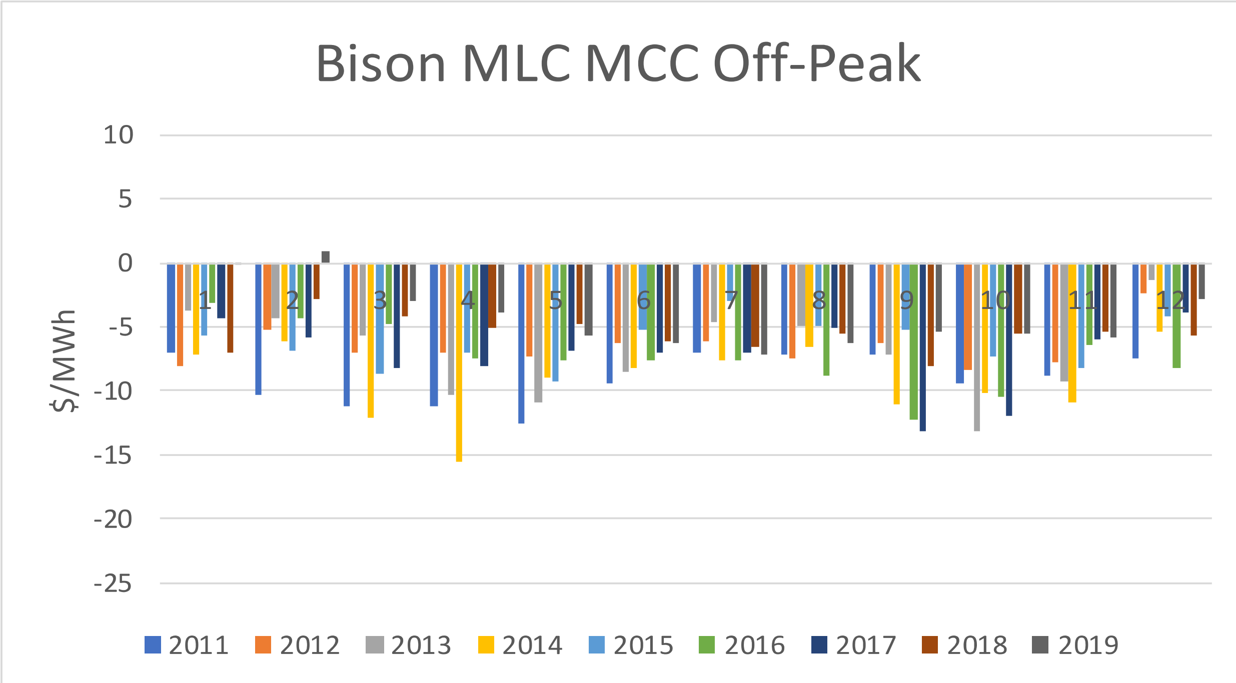

Figure D-5: Bison MLC/MCC Off-Peak

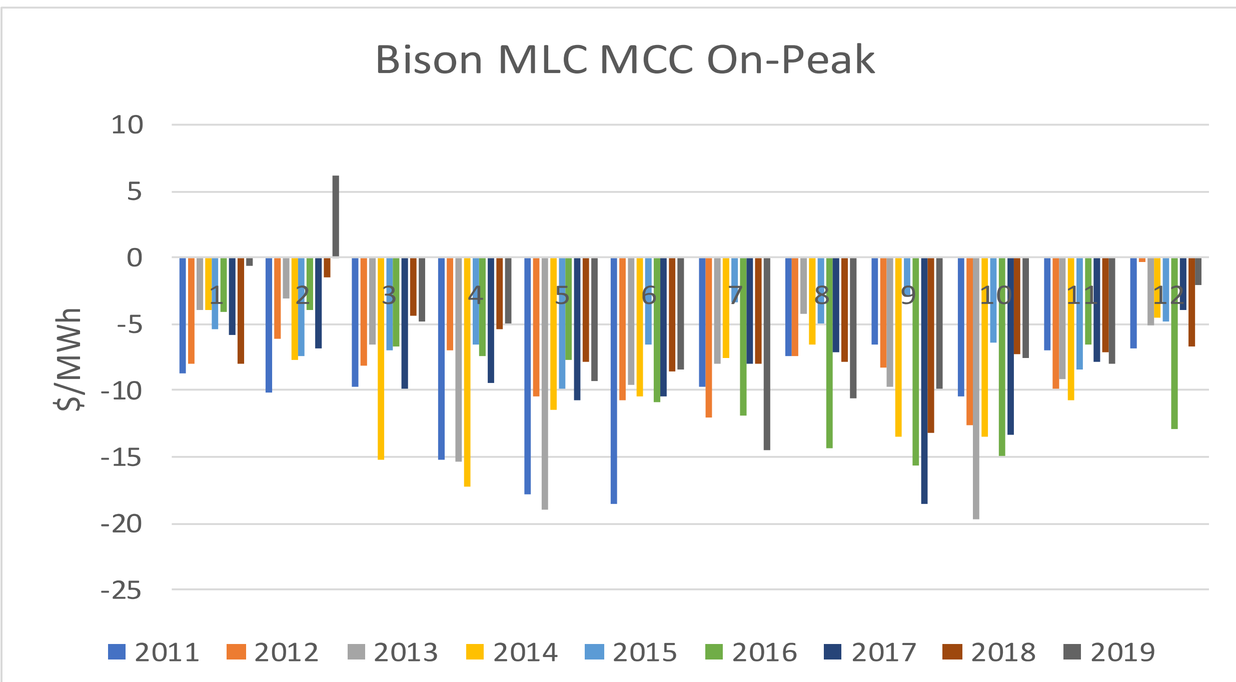

Figure D-6: Bison MLC/MCC On-Peak

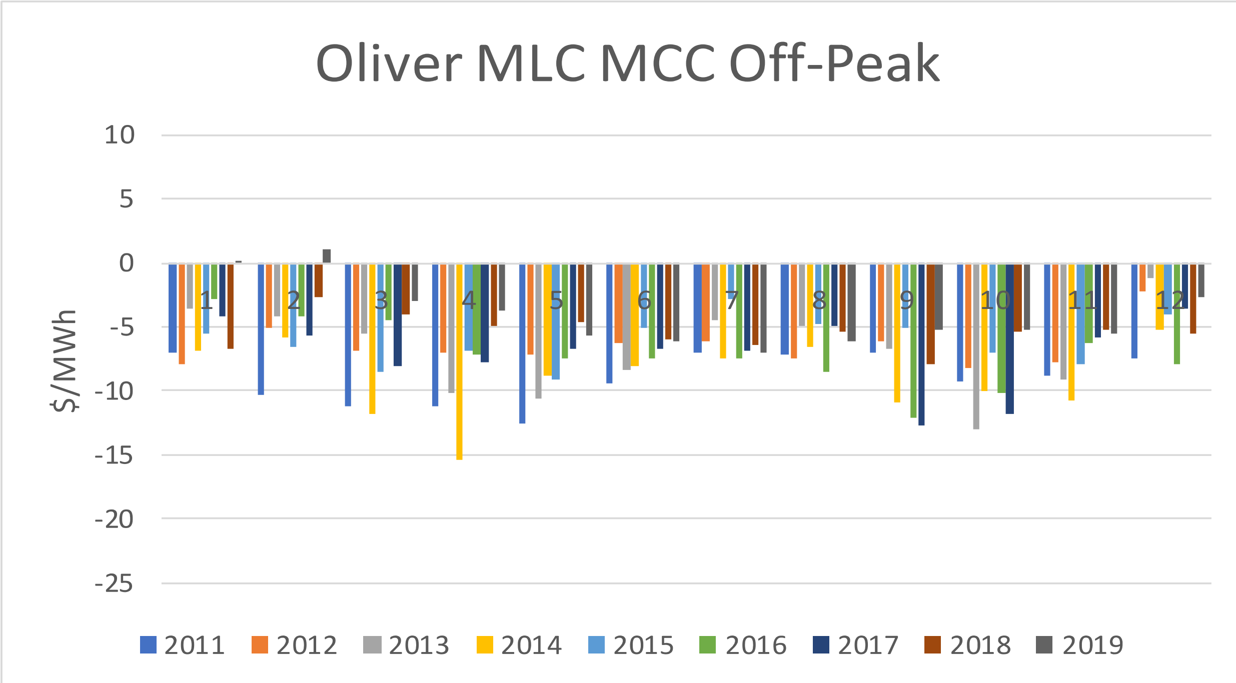

Figure D-7: Oliver MLC/MCC Off-Peak

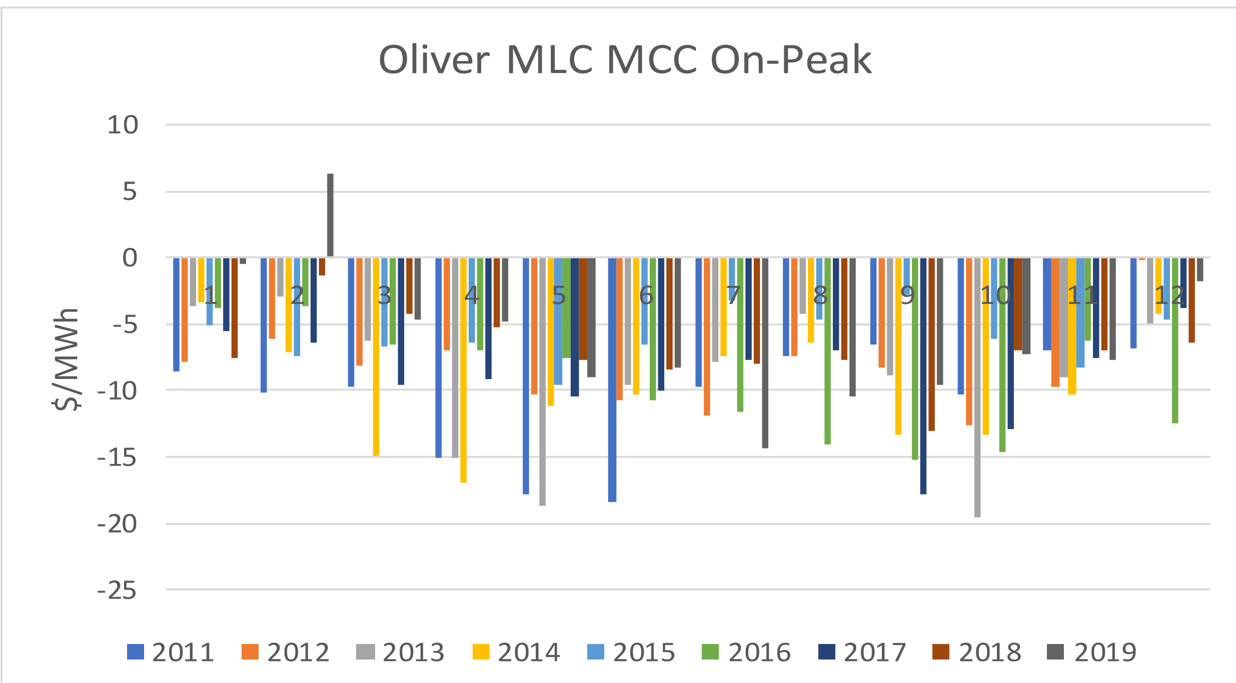

Figure D-8: Oliver MLC/MCC On-Peak

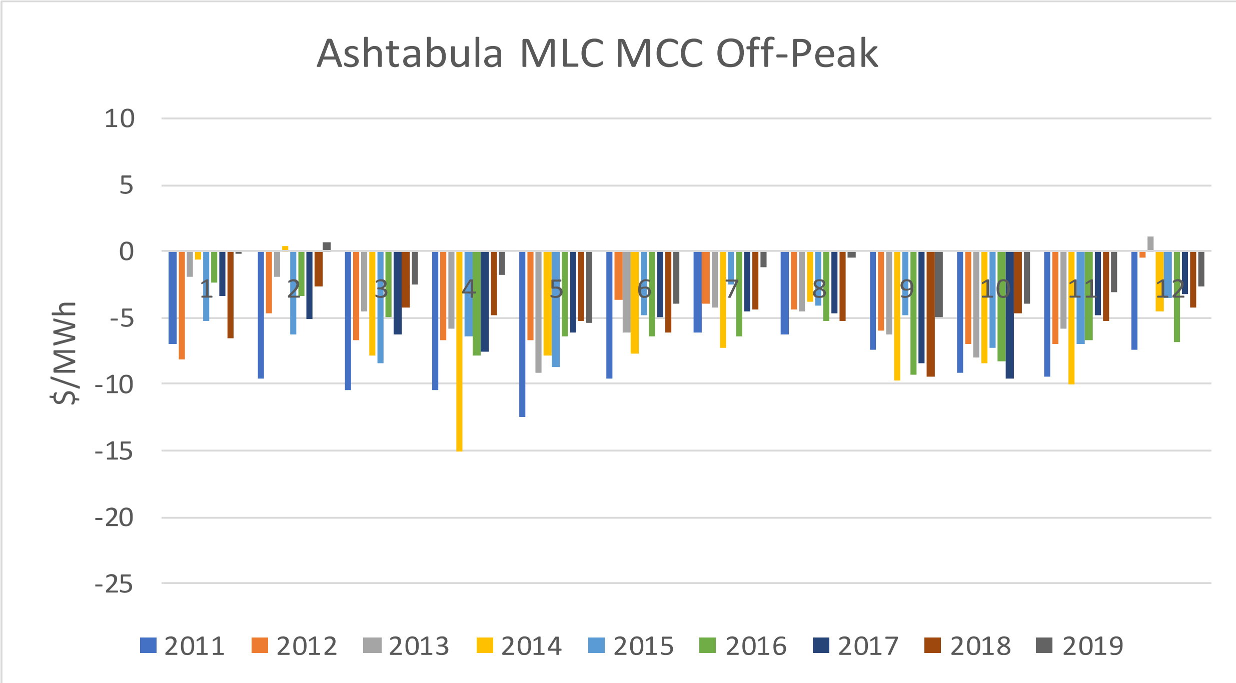

Figure D-9: Ashtabula MLC/MCC Off-Peak

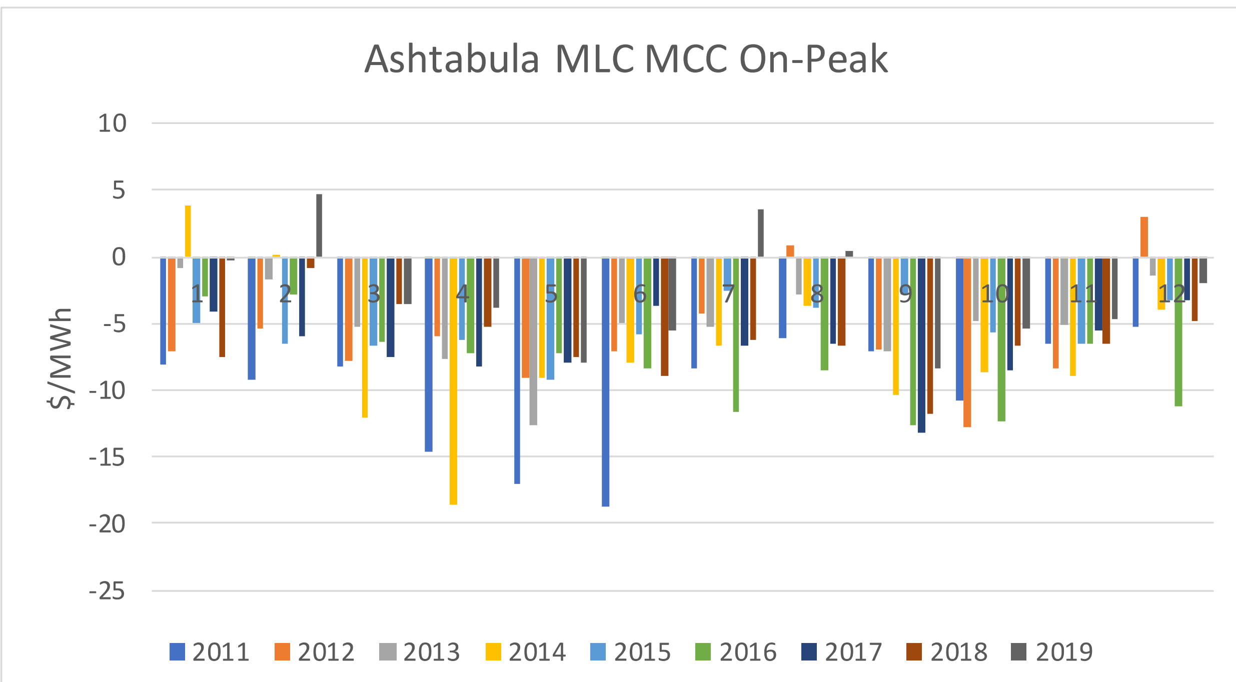

Figure D-10: Ashtabula MLC/MCC On-Peak

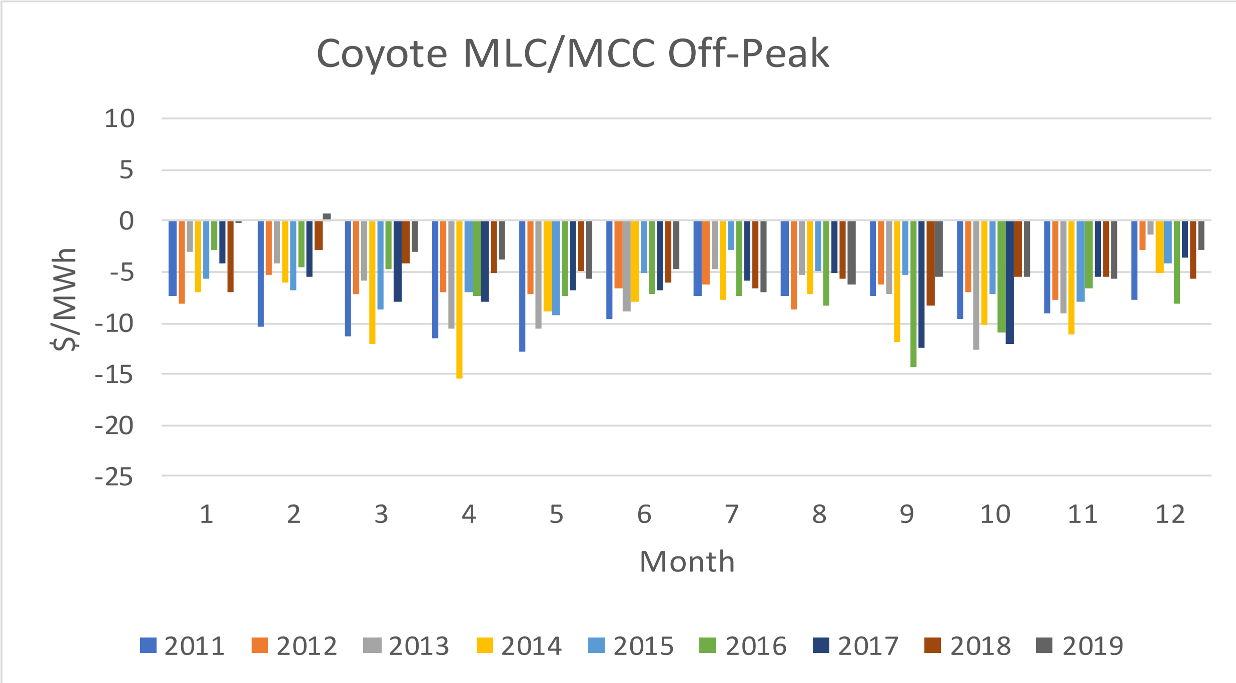

Figure D-11: Coyote MLC/MCC Off-Peak

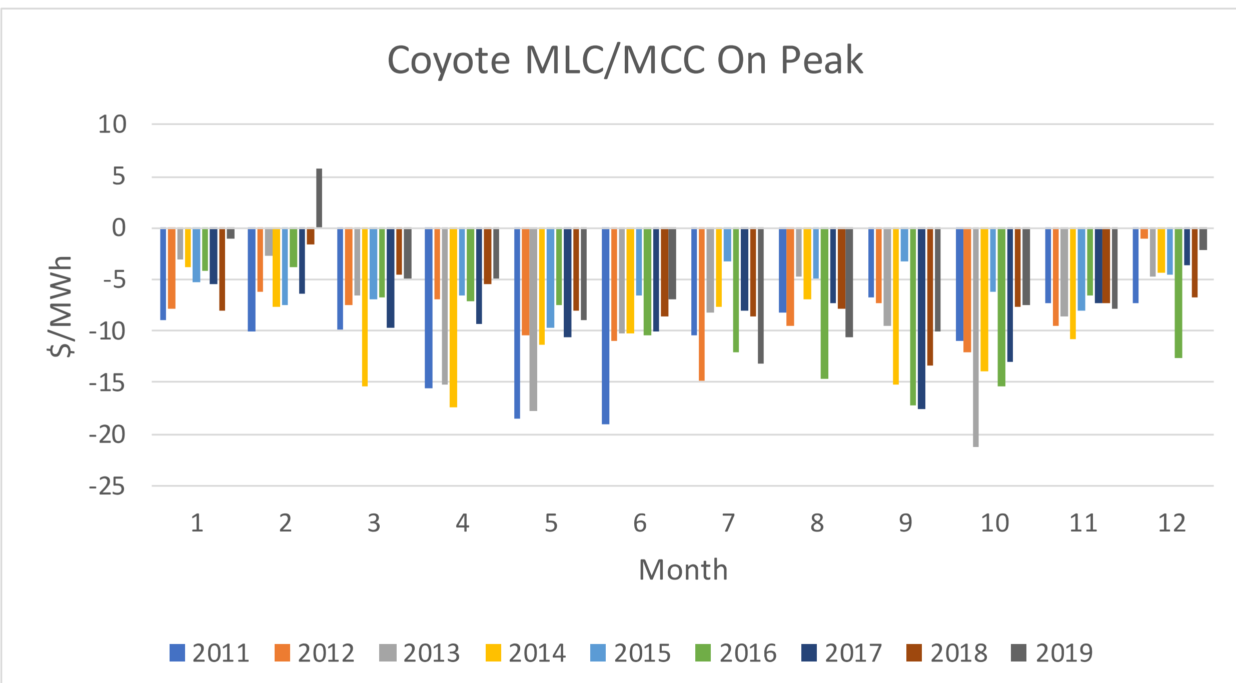

Figure D-12: Coyote MLC/MCC On-Peak

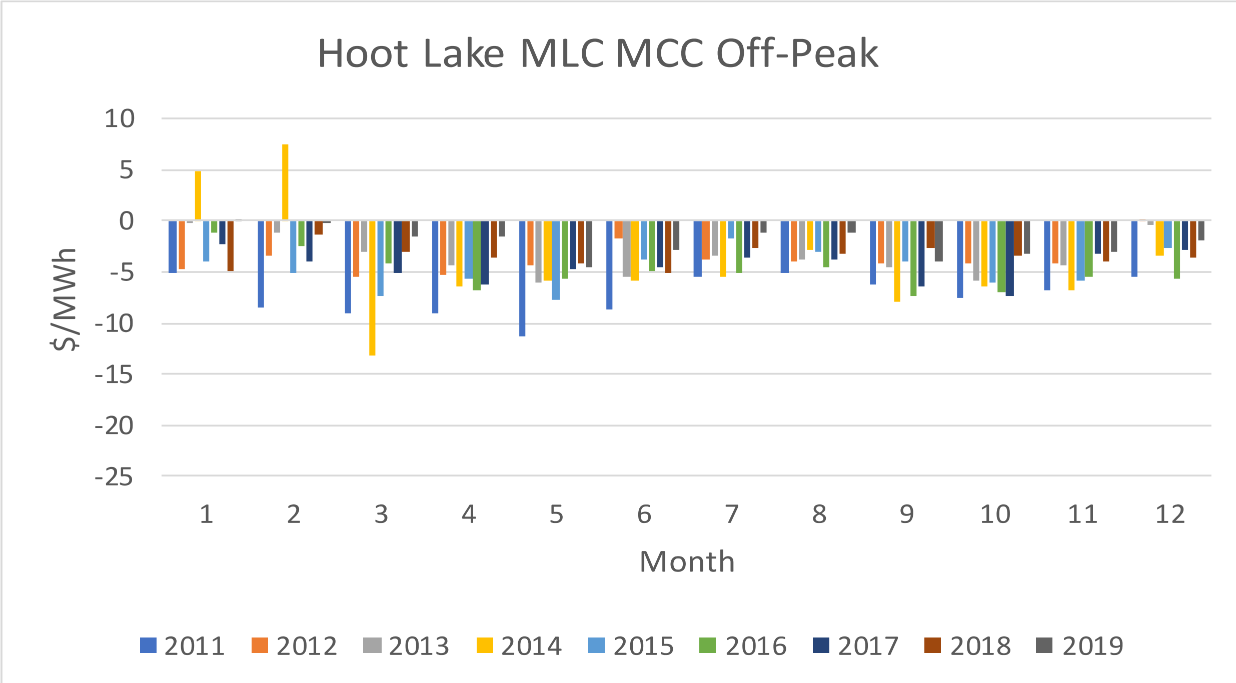

Figure D-13: Hoot Lake MLC/MCC Off-Peak

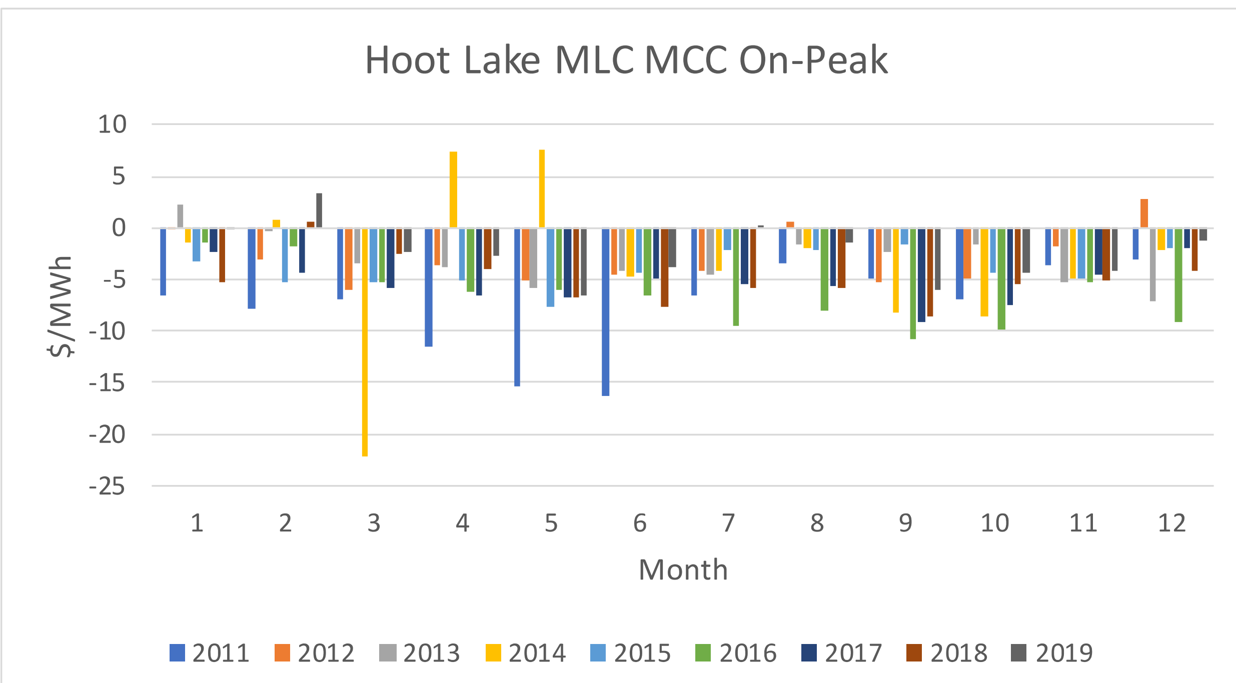

Figure D-14: Hoot Lake MLC/MCC On-Peak

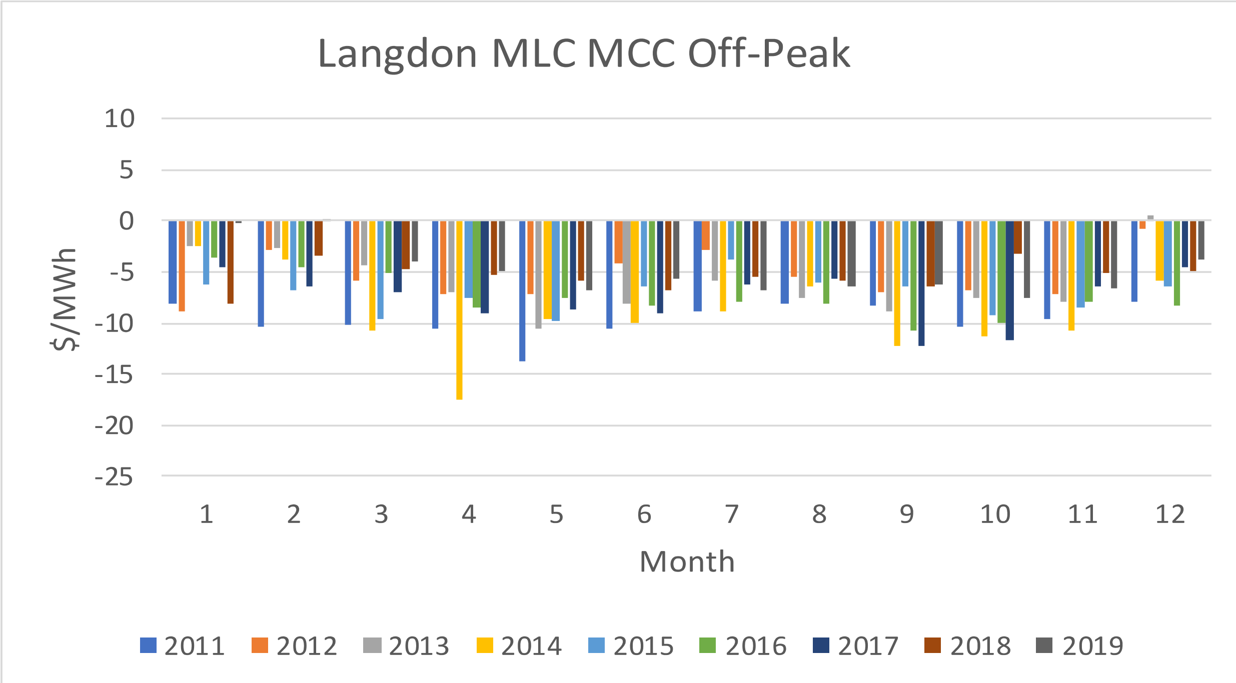

Figure D-15: Langdon MLC/MCC Off-Peak

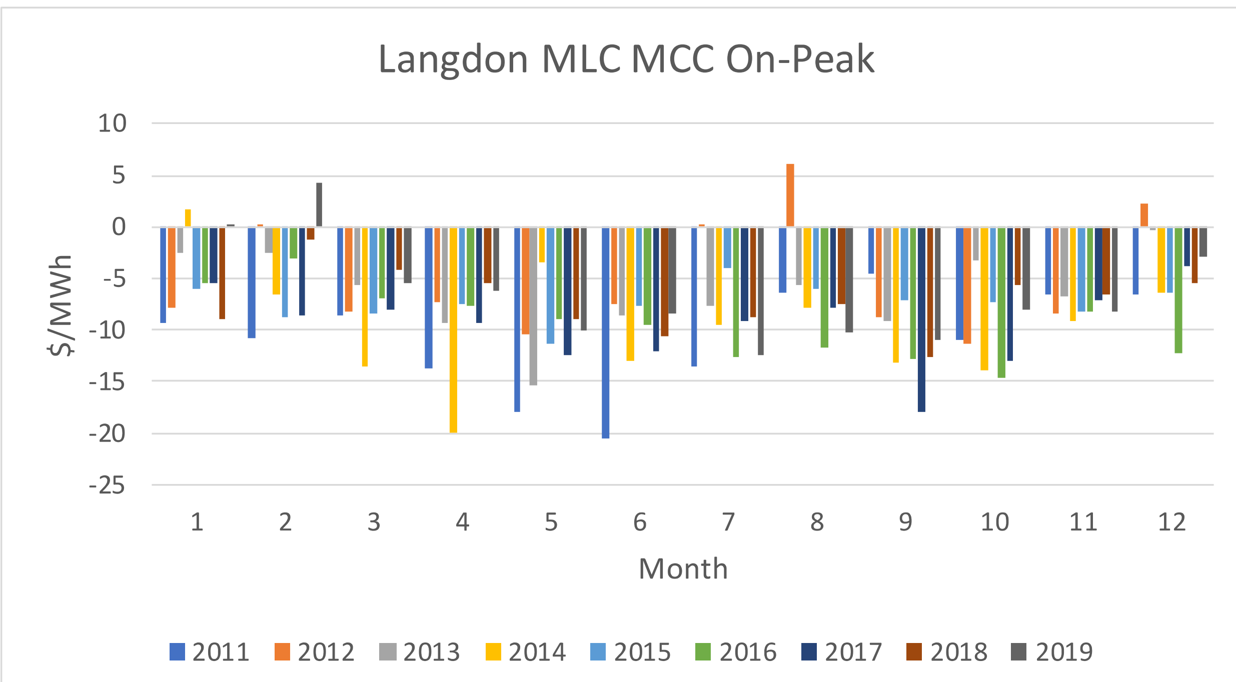

Figure D-16: Langdon MLC/MCC On-Peak

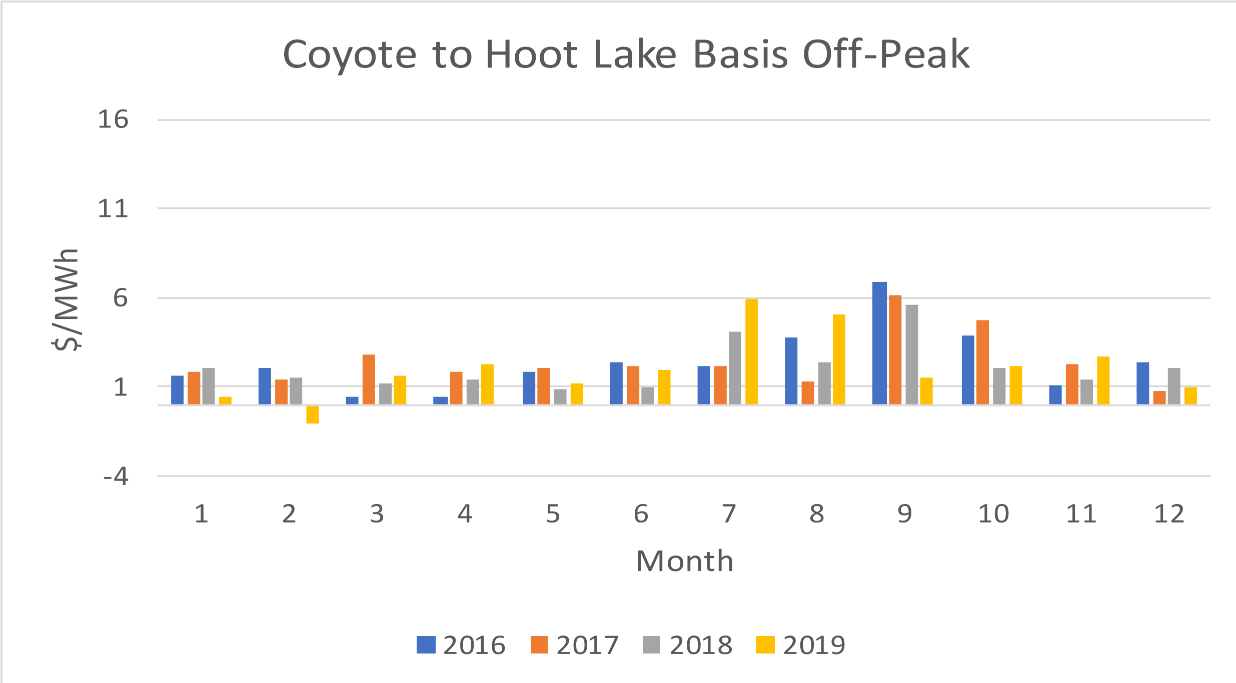

Figure D-17: Coyote to Hoot Lake Basis Off-Peak

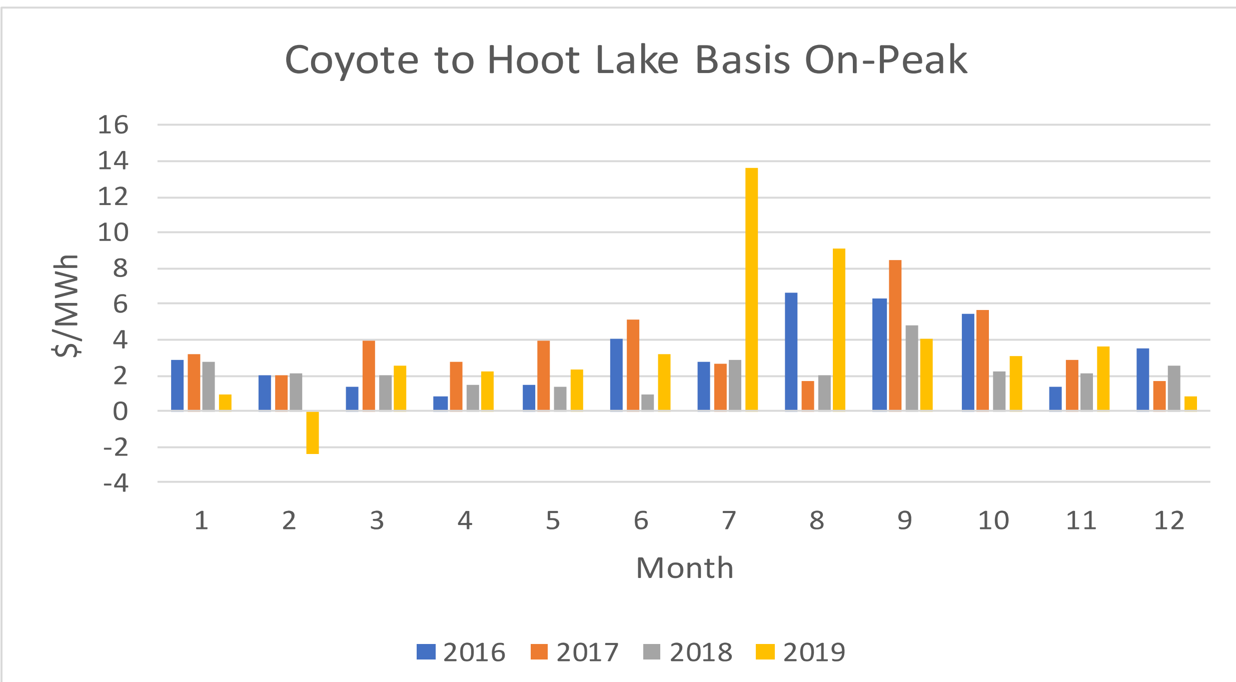

Figure D-18: Coyote to Hoot Lake Basis On-Peak

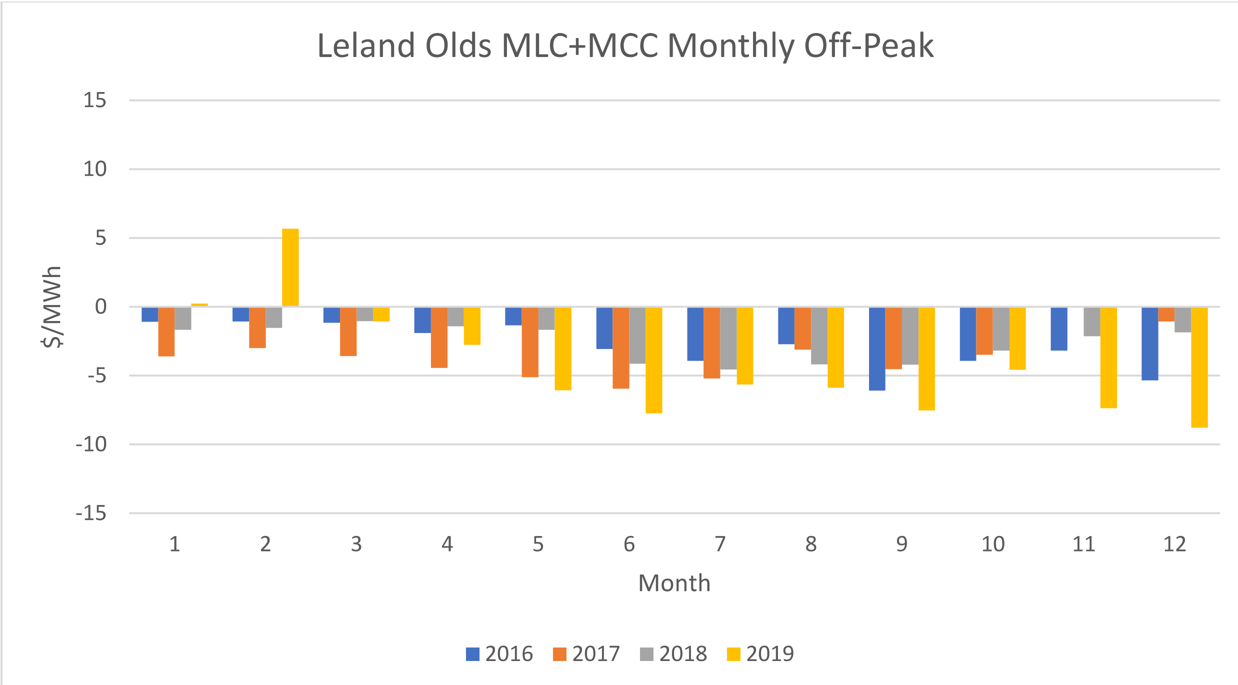

Figure D-19: Leland Olds MLC+MCC Monthly Off-Peak

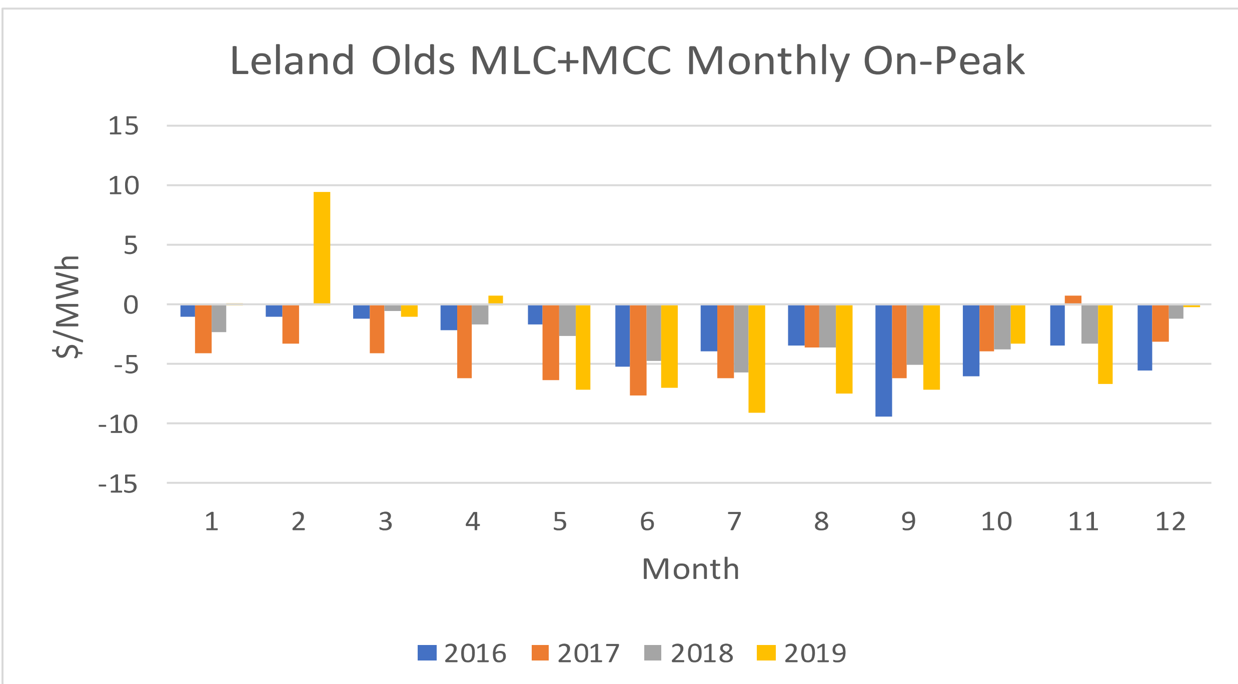

Figure D-20: Leland Olds MLC+MCC Monthly On-Peak

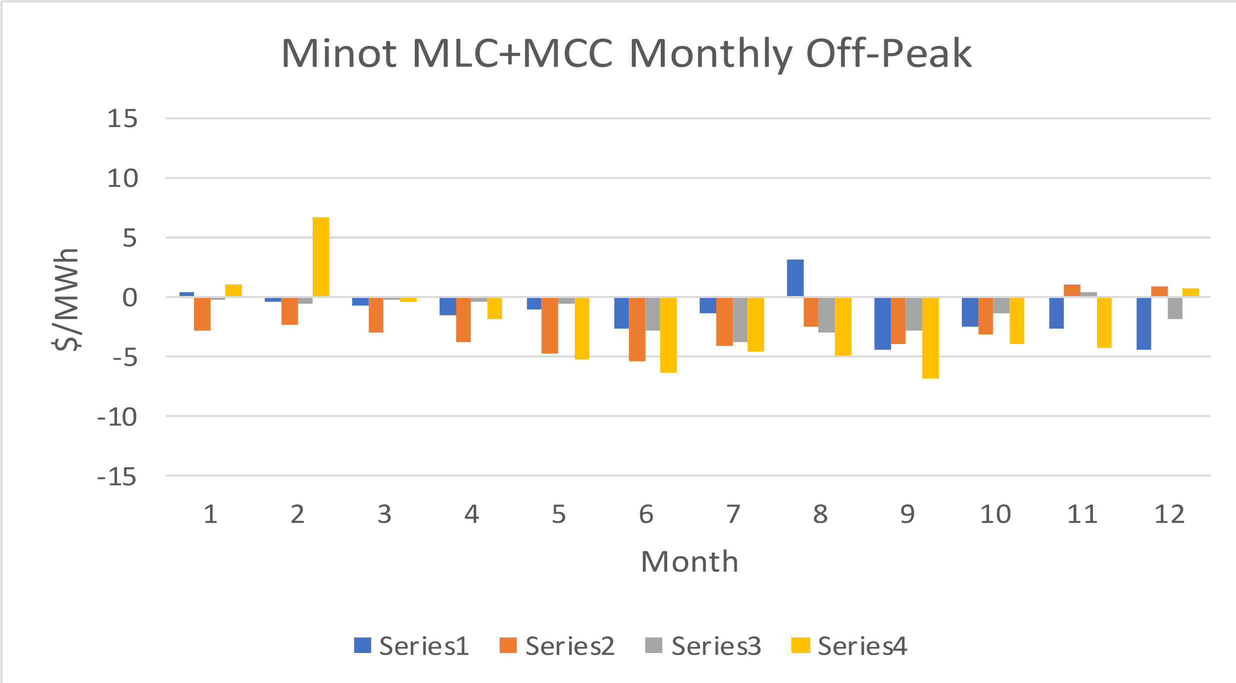

Figure D-21: Minot MLC+MCC Monthly Off-Peak

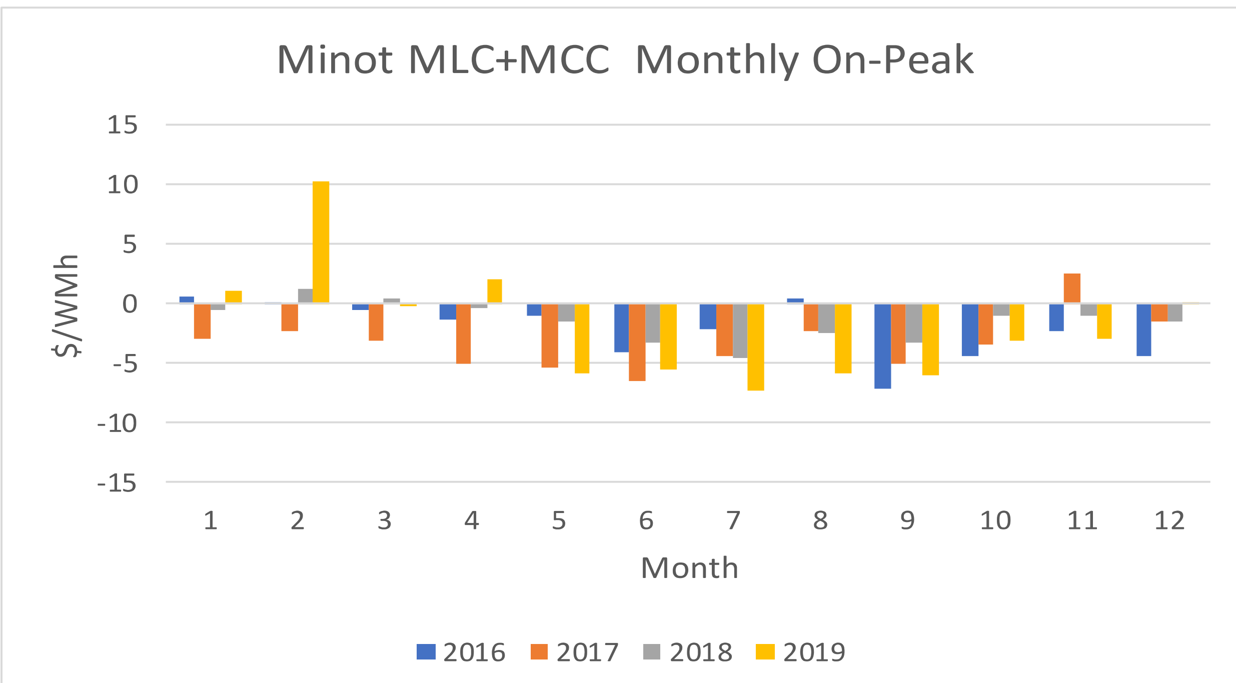

Figure D-22: Minot MLC+MCC Monthly On-Peak

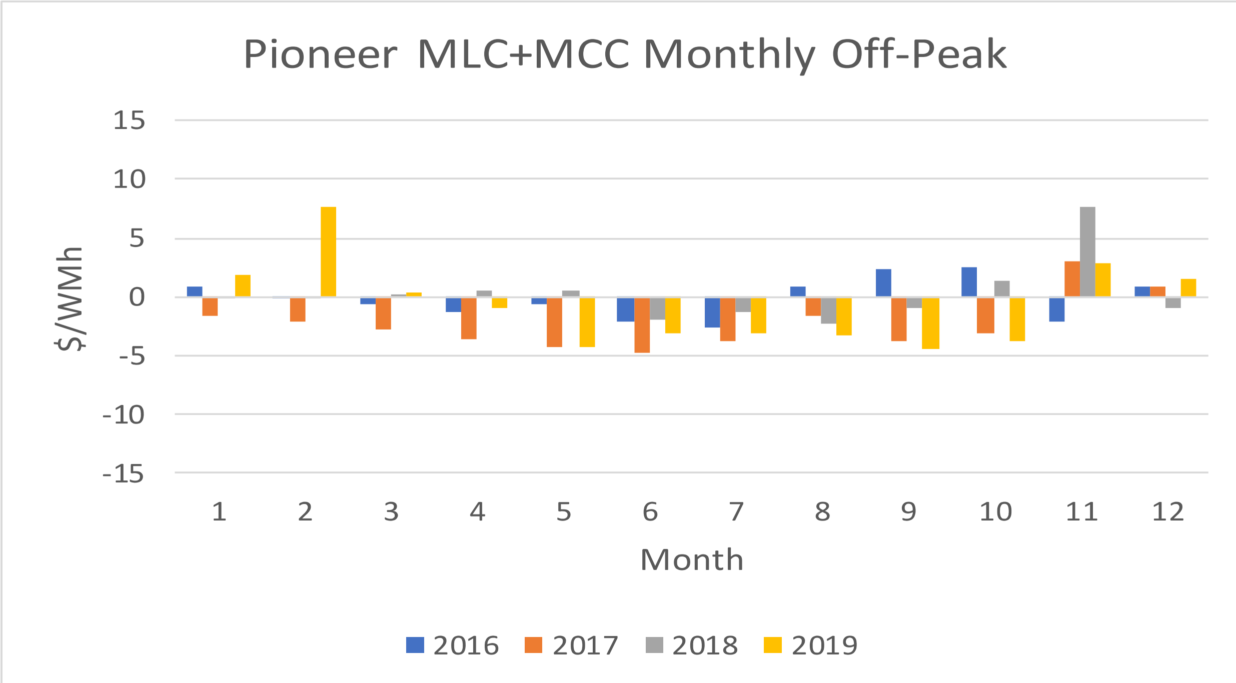

Figure D-23: Pioneer MLC+MCC Monthly Off-Peak

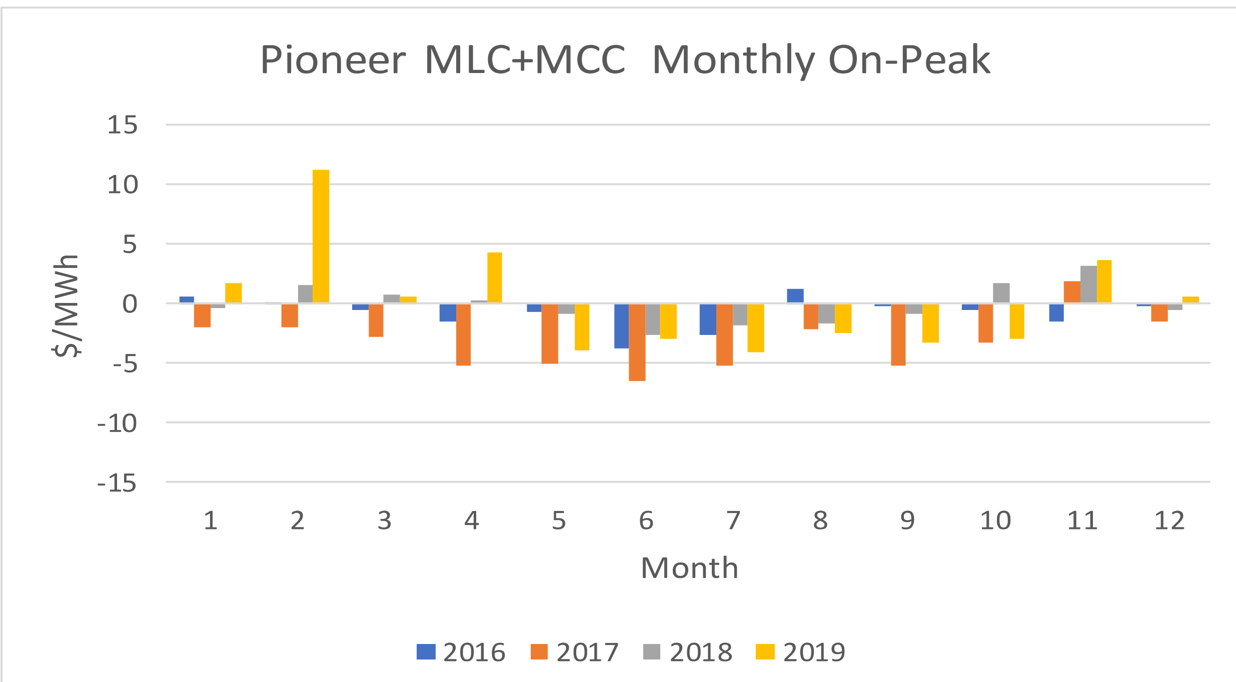

Figure D-24: Pioneer MLC+MCC Monthly On-Peak

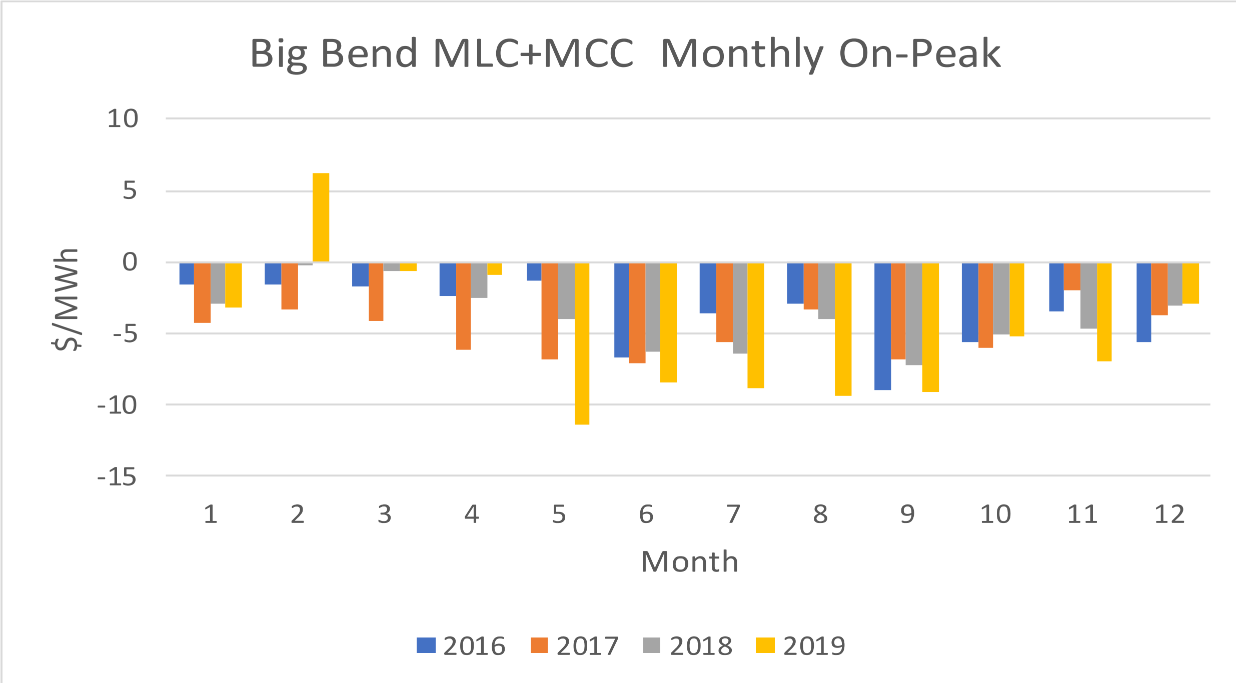

Figure D-25: Big Bend MLC+MCC Monthly On-Peak

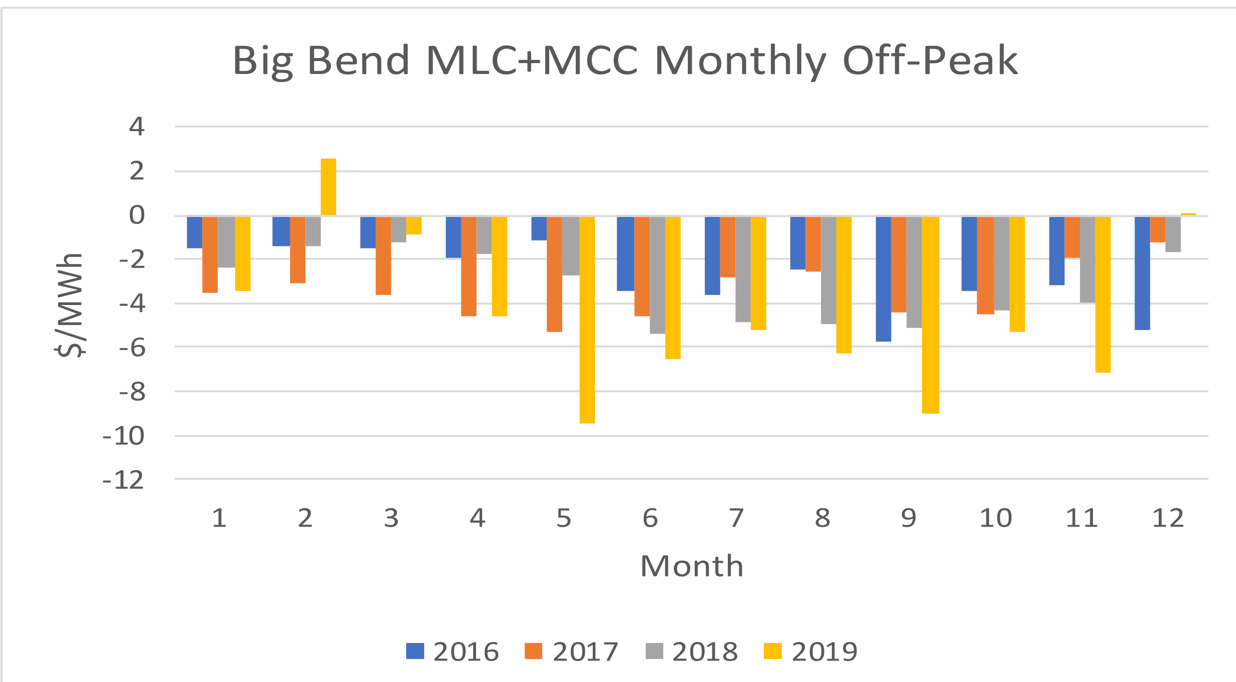

Figure D-26: Big Bend MLC+MCC Monthly Off-Peak

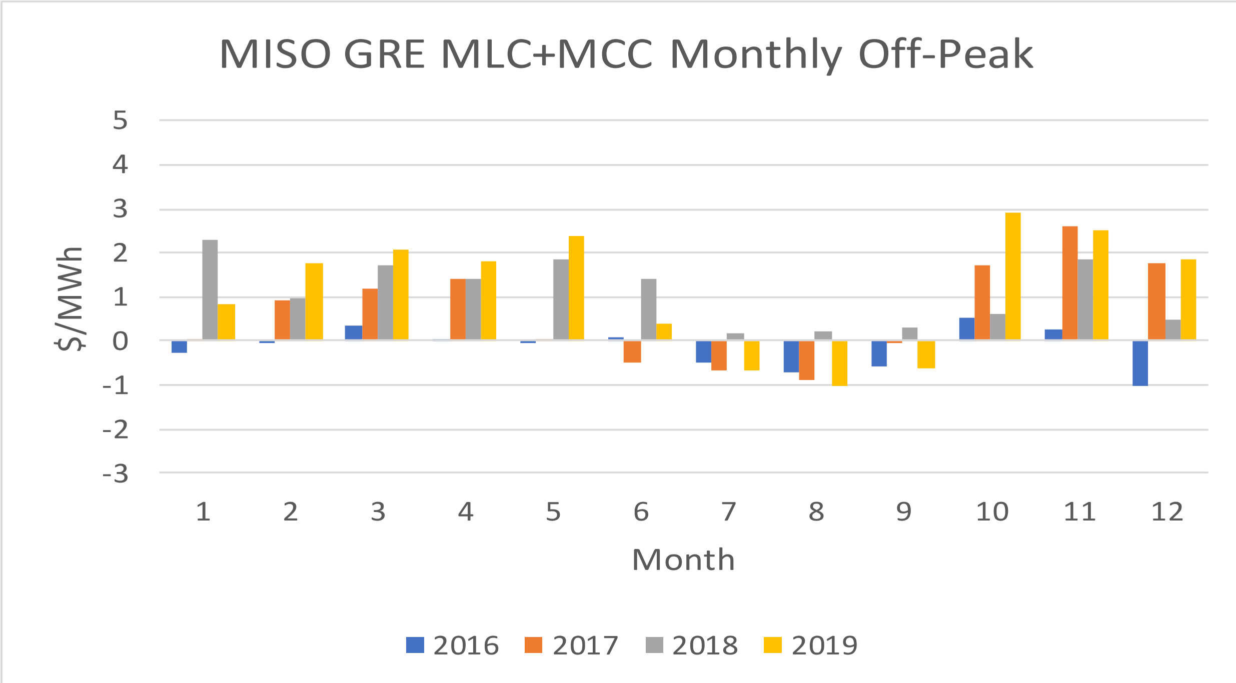

Figure D-27: MISO GRE MLC+MCC Monthly Off-Peak

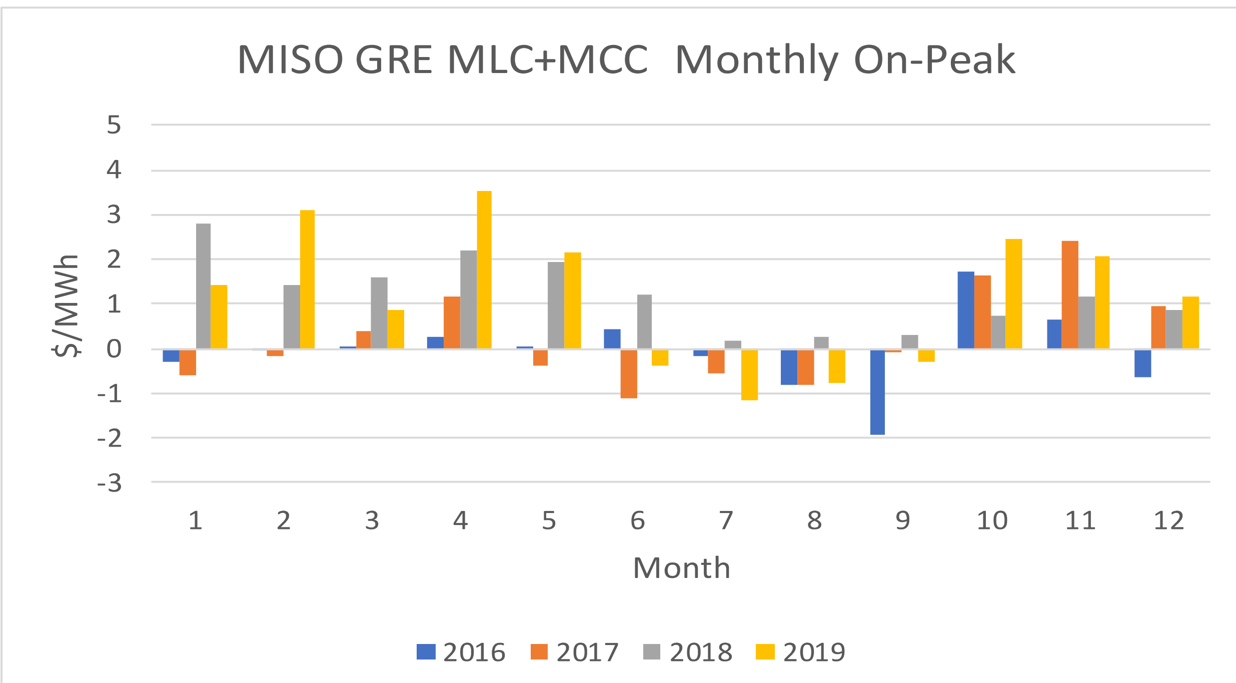

Figure D-28: MISO GRE MLC+MCC Monthly On-Peak