# State of Minnesota

## DEPARTMENT OF COMMERCE
## DIVISION OF ENERGY RESOURCES

**Utility Information Request**

Docket Number: E015/CN-12-1163 Date of Request: April 7, 2014

Requested From: David R. Moeller / Senior Attorney Response Due: April 17, 2014

Analyst Requesting Information: Steve Rakow

Type of Inquiry:

| | | |
|---|---|---|
| [ ] Financial | [ ] Rate of Return | [ ] Rate Design |
| [ ] Engineering | [ ] Forecasting | [ ] Conservation |
| [ ] Cost of Service | [ ] CIP | [ ] Other: |

***If you feel your responses are trade secret or privileged, please indicate this on your response.***

| Request No. | |
|---|---|
| 3 | Please provide an estimate of the impact of the proposed project on locational marginal prices (LMPs). |

Response:

Based on the analysis completed by Ventyx and summarized in the report *"Economic Analysis of the Great Northern Transmission Line 2022 and 2027"* the Project will slightly decrease the locational marginal price (LMP) within the state of Minnesota across both scenarios (Business as Usual and High Growth) and both timeframes (2022 and 2027) as shown in table 4.1 of the report.

Response by: Scott Hoberg

List sources of Information: Ventyx GNTL Economic Analysis

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# Economic Analysis of the Great Northern Transmission Line 2022 & 2027

**Prepared for:**
**Minnesota Power**

**Ventyx project no.: US-V00001330A**
**Final Report**

**Date:**

4/9/2014

**Prepared by:**
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# 1 Introduction

## 1.1 Executive Summary

Minnesota Power retained Ventyx, an ABB company (Ventyx) to perform detailed hourly nodal market simulation and forecasts to examine the benefits of constructing a new 500 kV transmission line from Manitoba to Minnesota.

The primary goal of this analysis was to quantify changes, caused by interconnecting this new line, in:

1. the estimated cost to serve demand for market participants in MISO and in Minnesota
2. the Locational Marginal Price (LMP) within the State of Minnesota

The metric "Adjusted Production Cost" (APC) as defined by the Midcontinent ISO (MISO) was used to estimate cost.

Based on the analysis it has been shown that for the two years studied (2022 and 2027) and two future scenarios (Business-As-Usual and High Growth) analyzed the impact of the Great Northern Transmission Line (GNTL) caused a decrease in LMPs within Minnesota. Also it is shown that the new transmission line causes no material change in the calculated Adjusted Production Cost based on MISO's APC methodology.

## 1.2 Scope

In early 2013, MISO performed its Northern Area Study (NAS), assessing the potential benefits of a variety of transmission projects – including the GNTL - that have been proposed to address the needs of MISO's northern tier of states, including Minnesota. That study was performed using the PROMOD IV market simulation model, analyzing the economic impacts in the years 2022 and 2027, and using MISO's MTEP 2012 database.

For this GNTL study, Ventyx considered using MISO's MTEP 2013 database for PROMOD IV. However, that database was still under revision by MISO at the time Ventyx undertook the GNTL study. Consequently, Ventyx obtained from MISO the NAS database, which was based on the MTEP 2012 data assumptions.

Ventyx compared the key assumptions, such as gas price forecasts, load growth, generator retirements, and new generation expansion, between the NAS data and the work-in-progress MTEP 2013 database. These data assumptions were reviewed with Minnesota Power staff, and they – along with Ventyx – agreed that the differences in key assumptions between MTEP 2012 and MTEP 2013 were minor, and that the GNTL study would proceed using the NAS database.

For this GNTL study, two futures were analyzed. The first was MISO's **Business-As-Usual** (BAU) future, representing mid-range economic assumptions. The second was MISO's **High Growth** (HG) future, representing assumptions of higher economic growth, including higher demand growth and higher gas prices.

Taking full advantage of the NAS database, Ventyx simulated the years 2022 and 2027 to capture the impact of additional generation resource development by Manitoba Hydro.

The generation schedules from hydro plants in Manitoba are as represented in MISO's NAS analysis, which was in turn derived by MISO and Manitoba Hydro as part of their joint "Manitoba Hydro Wind Synergy Study".

Note that these hydro generation schedules are assumed to be static between the pre-GNTL and post-GNTL cases. Consequently, the analysis presented here will not capture possible benefits deriving from modifications to Manitoba Hydro's generation scheduling practices that might be implemented when GNTL is in service. These simulations dispatch hydropower hourly schedules at a very low offer price, so that the energy will generally be taken by the market unless transmission limitations constrain its delivery. Except when it is curtailed by such congestion, this Manitoba Hydro export energy is a "price-taker", bought by the market at the local LMP.

### 1.3 About PROMOD IV software

PROMOD IV provides valuable information on the dynamics of the marketplace through its ability to determine the effects of transmission congestion on key system flowgates. PROMOD IV captures the constraints and limitations inherent in electric power transmission using a DC load flow algorithm. All major transmission equipment is modeled, including transformers, phase-angle regulators, DC ties, generation buses, load buses, and transmission lines with reactance and resistance inputs.

Transmission system modeling is fully integrated with the commitment and dispatch algorithm so that generators are scheduled, started, and cycled while enforcing transmission flow constraints.

PROMOD IV simultaneously optimizes transmission, generation, and ancillary service requirements for all 8760 hours to provide a robust security-constrained unit commitment and economic dispatch solution with bus-level LMP reporting. This study employed PROMOD IV, version 10.1.3.

# 2 Input Assumptions

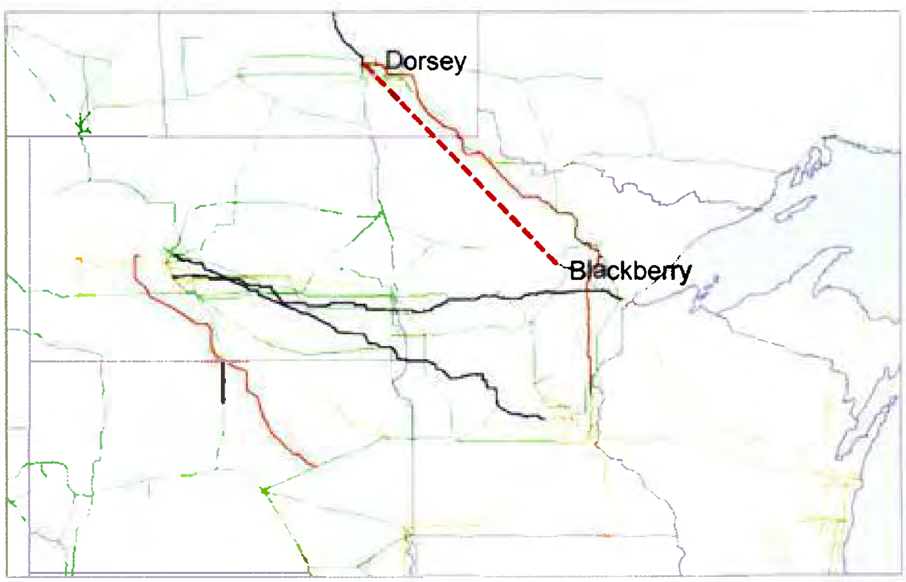
The majority of input assumptions were defined by Midcontinent ISO for their Northern Area Study.

## 2.1 Project Description

Minnesota Power, in partnership with Manitoba Hydro, proposes to construct a 500 kV transmission line from the International border that would terminate at the Blackberry substation in Itasca County (spanning an estimated 235 to 270 miles). The GNTL itself was modeled using MISO's data from NAS which was originally submitted by Minnesota Power. The project comprises the 500 kV branch from the Dorsey substation in Manitoba to the Blackberry substation in northwestern Minnesota, rated at 1732 MVA, plus additional system changes and upgrades at the Blackberry substation to feed these flows into the 230kV transmission system. Figure 1 below shows the general geographic arrangement of the project and is not representative of the project's actual route.

MISO's NAS analysis included as part of the project a 345kV extension from the Blackberry substation to the Arrowhead bus. This extension to the Arrowhead bus has not been represented in this Ventyx study.

**Figure 1 -- Great Northern Transmission Line Path**



## 2.2 Transmission Network

The scope of this database includes the entire Eastern Interconnect electric grid, excluding New England, Florida, Hydro-Quebec and the Canadian Maritime Provinces. These exclusions are sufficiently remote from Minnesota that they may be adequately represented by scaling their generation to meet their load and holding their net import or export constant.

The same network model is used for both 2022 and 2027. Therefore the only transmission difference examined is the presence or absence of the GNTL.

Two modifications were made to the MISO NAS data. First, the MISO ISO footprint was expanded to include the companies in the Entergy transmission region, which were to become integrated into the MISO market in December 2013. Second, the two futures were modified to include two conceptual transmission projects that were identified in the NAS study as significantly surpassing MISO's benefit/cost criterion:

- Hankinson – Wahpeton 230 kV upgrade
- Big Stone – Morris 115 kV upgrade

These two potential upgrades were determined by MISO to substantially increase the deliverability of wind generation from the Dakotas into Minnesota.

## 2.3 Generation

Table 2.1 presents the installed capacity of generation by fuel and type in MISO and in the companies that serve Minnesota load. Note the increase from 2022 to 2027 in wind, combined-cycle and combustion turbine capacity. These figures represent generic expansion and not specific proposals. There is no difference in the generation capacity mix between the Business As Usual and High Growth futures.

The schedule of hydropower from Manitoba was modeled per agreement between MISO and Manitoba Hydro for the Northern Area Study. Hydro energy is mostly represented as scheduled for peak-shaving (concentrated in higher-demand hours each day) with some flexibility to respond to market prices. This model mimics profit-maximizing bidding behavior without requiring that an offer price be assigned to the energy.

In the MISO NAS data, the hydro energy is offered to the MISO market at 0 $/MWh, shifting the supply curve to the right, with the expected effect of slightly lowering market clearing prices by displacing higher-cost generation in the receiving market. (Results of this study support this conjecture. Refer to Table 4.1.) However, the hydro energy is not free of charge; it is paid for at market clearing price. This study does not include the contract price for the energy, but it is supposed that the contract price is tied somehow to the market prices.

**Table 2.1 – MISO and MN Generation Mix by Technology, 2022 and 2027**

| MISO - High Growth and Business As Usual | | | | |
|---|---|---|---|---|
| Fuel | Technology | MW Capacity, 2022 | MW Capacity, 2027 | Change, 2022 to 2027 |
| COAL | ST -Coal | 60,496 | 60,496 | - |
| | IGCC | 1,077 | 1,077 | - |
| GAS | CC | 28,021 | 35,221 | 7,200 |
| | CT -Gas | 35,705 | 41,105 | 5,400 |
| | ST Gas | 16,788 | 16,780 | (8) |
| | ICE -Gas | 109 | 109 | - |
| OIL | CT -Oil | 4,486 | 4,486 | - |
| | ST -Oil | 158 | 158 | - |
| | ICE Oil | 381 | 381 | - |
| | CT -Kerosene | 67 | 67 | - |
| RENEWABLES | CT -Renewable | 36 | 36 | - |
| | ST -Renewable | 844 | 844 | - |
| | ICE-Renewable | 215 | 215 | - |
| | ST -Other | 167 | 167 | - |
| WATER | Hydro | 1,527 | 1,400 | (127) |
| | Pumped-Storage | 2,518 | 2,518 | - |
| URANIUM | Nuclear | 14,796 | 14,796 | - |
| WIND | Wind | 13,053 | 31,053 | 18,000 |
| SUN | Solar PV | 1,041 | 1,481 | 440 |
| DEMAND RESPONSE | Interruptible Loads | 9,169 | 9,169 | - |

| Minnesota - High Growth and Business As Usual | | | | |
|---|---|---|---|---|
| Fuel | Technology | MW Capacity, 2022 | MW Capacity, 2027 | Change, 2022 to 2027 |
| COAL | ST -Coal | 9,032 | 9,032 | - |
| | IGCC | - | - | - |
| GAS | CC | 2,897 | 4,097 | 1,200 |
| | CT -Gas | 7,315 | 7,315 | - |
| | ST -Gas | 267 | 259 | (8) |
| | ICE -Gas | 15 | 15 | - |
| OIL | CT -Oil | 1,690 | 1,690 | - |
| | ST -Oil | - | - | - |
| | ICE -Oil | 188 | 188 | - |
| | CT -Kerosene | 47 | 47 | - |
| RENEWABLES | CT -Renewable | - | - | - |
| | ST -Renewable | 452 | 452 | - |
| | ICE-Renewable | 26 | 26 | - |
| | ST -Other | 51 | 51 | - |
| WATER | Hydro | 375 | 350 | (25) |
| | Pumped-Storage | - | - | - |
| URANIUM | Nuclear | 2,366 | 2,366 | - |
| WIND | Wind | 6,583 | 11,286 | 4,703 |
| SUN | Solar PV | 220 | 320 | 100 |
| DEMAND RESPONSE | Interruptible Loads | 2,259 | 2,259 | - |

## 2.4 Demand

Demand in each area follows a synthetic hourly schedule which has been determined from load data for the years 2003-2009. This schedule is scaled so as to match the peak and annual energy figures assumed as in the table below.

Table 2.2 presents demand figures, described by annual peak and energy for MISO and for the companies that serve Minnesota load. The latter account for about 10 percent of MISO demand.

**Table 2.2 – MISO and MN (weighted by sales) Demand, 2022 and 2027**

| | | 2022 BAU | 2027 BAU | Growth Rate | 2022 HG | 2027 HG | Growth Rate |
|---|---|---|---|---|---|---|---|
| MISO | Peak MW | 132,079 | 140,247 | 1.2% | 141,857 | 156,279 | 2.0% |
| | Energy GWh | 736,160 | 796,278 | 1.6% | 802,554 | 907,110 | 2.5% |
| Minnesota Companies | Peak MW | 13,923 | 15,019 | 1.5% | 14,990 | 16,804 | 2.3% |
| | Energy GWh | 80,695 | 86,895 | 1.5% | 87,964 | 99,021 | 2.4% |

## 2.5 Fuel Prices

Table 2.3 presents fuel prices for the Business as Usual and High Growth futures. Note that fuel prices are generally about 10% higher in the High Growth future.

**Table 2.3 – Fuel Prices (nominal $/MBtu)**

| Business as Usual | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gas (Henry Hub) | 2022 | $ 4.95 | $ 4.93 | $ 4.87 | $ 4.66 | $ 4.65 | $ 4.67 | $ 4.71 | $ 4.74 | $ 4.75 | $ 4.79 | $ 4.89 | $ 5.05 |
| | 2027 | $ 5.40 | $ 5.38 | $ 5.32 | $ 5.09 | $ 5.08 | $ 5.11 | $ 5.15 | $ 5.18 | $ 5.19 | $ 5.24 | $ 5.34 | $ 5.51 |
| Oil #6 | 2022 | $ 13.30 | $ 12.96 | $ 12.99 | $ 13.27 | $ 13.64 | $ 13.93 | $ 14.21 | $ 14.35 | $ 14.37 | $ 14.26 | $ 13.99 | $ 13.62 |
| | 2027 | $ 14.50 | $ 14.13 | $ 14.16 | $ 14.47 | $ 14.87 | $ 15.19 | $ 15.49 | $ 15.65 | $ 15.66 | $ 15.54 | $ 15.25 | $ 14.85 |
| Oil #2 | 2022 | $ 20.00 | $ 19.76 | $ 19.58 | $ 19.50 | $ 19.44 | $ 19.42 | $ 19.63 | $ 20.28 | $ 21.04 | $ 21.23 | $ 20.88 | $ 20.36 |
| | 2027 | $ 21.81 | $ 21.54 | $ 21.35 | $ 21.26 | $ 21.19 | $ 21.17 | $ 21.39 | $ 22.11 | $ 22.93 | $ 23.14 | $ 22.76 | $ 22.19 |
| Kerosene | 2022 | $ 21.17 | $ 21.03 | $ 21.02 | $ 21.09 | $ 21.17 | $ 21.39 | $ 21.70 | $ 22.29 | $ 22.91 | $ 22.89 | $ 22.34 | $ 21.51 |
| | 2027 | $ 23.08 | $ 22.93 | $ 22.91 | $ 22.98 | $ 23.08 | $ 23.32 | $ 23.65 | $ 24.29 | $ 24.97 | $ 24.95 | $ 24.35 | $ 23.45 |

| Business as Usual | | Average | Min | Max |
|---|---|---|---|---|
| Coal (MN units) | 2022 | $ 2.31 | $ 1.48 | $ 3.48 |
| | 2027 | $ 2.52 | $ 1.61 | $ 3.79 |

| High Growth | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gas (Henry Hub) | 2022 | $ 5.55 | $ 5.53 | $ 5.46 | $ 5.22 | $ 5.21 | $ 5.24 | $ 5.28 | $ 5.31 | $ 5.32 | $ 5.38 | $ 5.48 | $ 5.66 |
| | 2027 | $ 6.41 | $ 6.38 | $ 6.31 | $ 6.04 | $ 6.03 | $ 6.07 | $ 6.11 | $ 6.15 | $ 6.16 | $ 6.22 | $ 6.33 | $ 6.54 |
| Oil #6 | 2022 | $ 14.91 | $ 14.53 | $ 14.56 | $ 14.88 | $ 15.30 | $ 15.62 | $ 15.93 | $ 16.09 | $ 16.11 | $ 15.99 | $ 15.68 | $ 15.27 |
| | 2027 | $ 17.21 | $ 16.77 | $ 16.81 | $ 17.17 | $ 17.66 | $ 18.03 | $ 18.39 | $ 18.58 | $ 18.59 | $ 18.45 | $ 18.10 | $ 17.62 |
| Oil #2 | 2022 | $ 22.43 | $ 22.16 | $ 21.95 | $ 21.86 | $ 21.80 | $ 21.77 | $ 22.00 | $ 22.74 | $ 23.59 | $ 23.80 | $ 23.40 | $ 22.82 |
| | 2027 | $ 25.89 | $ 25.57 | $ 25.34 | $ 25.24 | $ 25.16 | $ 25.13 | $ 25.40 | $ 26.24 | $ 27.22 | $ 27.47 | $ 27.01 | $ 26.34 |
| Kerosene | 2022 | $ 23.74 | $ 23.58 | $ 23.57 | $ 23.64 | $ 23.74 | $ 23.98 | $ 24.33 | $ 24.99 | $ 25.68 | $ 25.66 | $ 25.04 | $ 24.12 |
| | 2027 | $ 27.40 | $ 27.22 | $ 27.20 | $ 27.28 | $ 27.40 | $ 27.68 | $ 28.08 | $ 28.84 | $ 29.65 | $ 29.62 | $ 28.90 | $ 27.83 |

| High Growth | | Average | Min | Max |
|---|---|---|---|---|
| Coal (MN units) | 2022 | $ 2.59 | $ 1.66 | $ 3.90 |
| | 2027 | $ 2.99 | $ 1.91 | $ 4.50 |

## 2.6 Emissions Prices

All emissions ($SO_2$, $NO_X$, $CO_2$) were assigned zero cost in 2022 and 2027.

# 3 Methodology

This analysis of the GNTL looks at the benefits to MISO and Minnesota in two ways:

1. Savings due to reduced Adjusted Production Costs (APC)
2. Changes in locational marginal prices (LMPs)

## 3.1 Adjusted Production Cost

APC is a common measure of energy production costs, used by the various ISOs to represent the net effect of market settlements when determining the cost to serve load. It is basically the cost of market purchases less revenues from market sales, modified by imports from and exports to neighboring markets.

Since it is impractical to try to capture the details of an ISO settlement statement, given uncertainty in the allocation of hedges, in the net impacts of market uplift charges, and in any particular market participant's bidding and scheduling policies, APC looks at the ISO settlement statement from the perspective of a vertically integrated utility (the predominant corporate structure of major market participants in MISO). In this view, the ISO market settlement simply represents a pricing mechanism for net purchases from, or sales to, the market.

In PROMOD IV simulations, a market participant ("company") will buy or sell among the other companies within its local market ("pool", such as MISO or PJM), depending on the state of the security-constrained dispatch each hour. The APC is calculated using the results of the PROMOD IV simulations, assuming that each company's net production is applied first to meet its own demand. Any surplus (or deficit) is sold to (or purchased from) other companies participating in the pool/market at the hourly rate.

According to MISO's APC definition, the hourly rate for sales to the pool is a blended marginal price for "net supply" by that company. It is the average of the LMPs at the company's own generator nodes, weighted by MWh production at each node. The hourly rate for energy purchased from the pool is a blend of the "net supply" prices for all companies that happen to be selling energy in the hour.

A company can also be allocated a share of economic purchases and sales that PROMOD IV schedules between pools, limited by economic hurdle rates defined between each pair of pools, and limited by the ability of the transmission system to carry these transfers. In MISO's NAS database, Manitoba Hydro is considered to be its own pool, as is the group of MRO companies that are currently neither in MISO nor in SPP[1].

MISO's definition of APC sets the price for any such inter-pool purchases and sales at the pool-wide generation-weighted LMP. Because this GNTL analysis focuses on the market interaction between Manitoba and Minnesota, Ventyx believes that it is more appropriate to price any such allocated inter-pool purchases and sales at the individual company generation-weighted LMP, and has used that pricing methodology in this analysis.

[1] The economic hurdle between MISO and Manitoba Hydro is set to zero.

This report summarizes the APC benefits of the GNTL on a MISO-wide basis and on a State of Minnesota basis. The latter Minnesota results are calculated by first multiplying the APC value for each company by the fraction of its load that is within Minnesota and then summing the result for all companies. The load fractions have been extracted from a prior study performed by Analysis Group (*"LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Supplemental Analysis"*, April 2013, Table 2, page 8).

### 3.2 LMP in Minnesota

An additional measure of the benefit of the GNTL is its impact on wholesale prices. PROMOD IV calculates from its nodal results the load-weighted zone LMP for each of the companies. These zone-level values are then weighted together, using load multiplied by the same factors from the Analysis Group report, to obtain a Minnesota load-weighted LMP. The company values are also averaged to obtain a MISO-wide load-weighted LMP. The change in these LMPs attributed to the GNTL being in service provides a measure of the benefits in terms of unhedged demand costs.

PROMOD IV calculates LMP including all three components: marginal energy, marginal congestion and marginal loss. It performs a Security-Constrained Unit Commitment (SCUC) and Economic Dispatch (SCED), such that the resulting output from all generators not only respects all generation operational constraints, including planned and forced outages, but also ensures that power flows on transmission facilities do not overload any facility for which a capacity limit has been provided, either in "system intact" (n-0) conditions or under the hypothetical loss of one facility (n-1). The transmission constraints are consistent with those used in the MISO NAS study.

# 4 Discussion of Results

Results are summarized below and interpreted.

### 4.1 Locational Marginal Price (LMP) in Minnesota

Table 4.1 presents the forecast change in LMP for Minnesota load, for the years 2022 and 2027 in the two future scenarios. The LMPs are load-weighted averages, expressed in nominal $/MWh.

In general, the wholesale prices show a decrease when GNTL is in service, as expected. In both scenarios, the relatively larger LMP decrease in 2027 is explained by the availability in that year of greater quantities of hydro-electric energy due to the commissioning of additional generating resources in Manitoba.

The comparatively lesser LMP decrease in the High Growth future is explained by observing that Manitoba Hydro's internal demand is forecast higher in the High Growth future, reducing the amount of energy that Manitoba Hydro has available for export, compared to the Business As Usual future.

**Table 4.1 -- Change in Load-Weighted LMPs Related to GNTL**

| | | | LMP for Minnesota Load (Weighted-Average) | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Average LMP ($/MWh) | | | Change due to 500 kV GNTL line (in - out, $/MWh) | | |
| | Scenario | GNTL status | On-peak | Off-peak | All hours | On-peak | Off-peak | All hours |
| 2022 | BAU | out | $ 38.35 | $ 25.91 | $ 31.82 | -0.08 | 0.00 | -0.04 |
| | | in | $ 38.28 | $ 25.91 | $ 31.79 | | | |
| | HG | out | $ 50 05 | $ 34.65 | $ 41.97 | -0.01 | 0.00 | -0 01 |
| | | in | $ 50.04 | $ 34.65 | $ 41.96 | | | |
| 2027 | BAU | out | $ 42.29 | $ 28.70 | $ 35.18 | -1.35 | -0.26 | -0.78 |
| | | in | $ 40.95 | $ 28.44 | $ 34.40 | | | |
| | HG | out | $ 52.85 | $ 39.13 | $ 45.67 | -0.53 | -0.09 | -0.30 |
| | | in | $ 52.32 | $ 39.04 | $ 45.37 | | | |

The change in LMP is the difference of the LMP with the GNTL in service minus the LMP without the GNTL in service, rounded to the nearest penny.

### 4.2 Adjusted Production Cost

Table 4.2 presents the forecast change in Adjusted Production Cost for MISO as a whole and for Minnesota only, in nominal dollars (2022$ and 2027$).

The results in Table 4.2 are given to four decimals to show clearly that the GNTL causes no material change, either increase or decrease, to the cost to serve load as computed by MISO's APC methodology.

The Adjusted Production Cost does not change despite the reduction in LMP that is enabled by the GNTL. This is because, although the cost of energy purchases may decrease for entities that are net purchasers, so too may the revenues (profits) decrease for entities that are net sellers of energy. The profits of the net sellers are further reduced because the additional energy purchased from Manitoba Hydro reduces the volume of energy that those net sellers would otherwise have produced and sold.

A vertically-integrated utility with a good balance between economic generation assets and demand would therefore see little change in its market settlement as average LMPs shift up or down.

**Table 4.2 -- Change in Adjusted Production Costs Related to GNTL**

| | | | Adjusted Production Cost ($Billion) | | Change due to GNTL (in - out, $Billion) | |
|---|---|---|---|---|---|---|
| | Scenario | GNTL status | MISO | Minnesota | MISO | Minnesota |
| 2022 | BAU | out | 18.8001 | 1.6275 | -0.0004 | 0.0002 |
| | | in | 18.7996 | 1.6277 | | |
| | HG | out | 24.0776 | 2.1563 | 0.0004 | 0.0030 |
| | | in | 24.0780 | 2.1593 | | |
| 2027 | BAU | out | 21.9331 | 1.9494 | 0.0022 | -0.0033 |
| | | in | 21.9354 | 1.9460 | | |
| | HG | out | 31.5224 | 2.8627 | 0.0114 | -0.0016 |
| | | in | 31.5338 | 2.8610 | | |

The change in cost is the difference of the adjusted production cost with the GNTL in service minus the adjusted production cost without the GNTL in service.

# 5 Carbon Sensitivity

As a simple sensitivity, Ventyx repeated the simulations of the Business As Usual scenarios with the assumption of the following CO2 regulation costs (in Nominal $/ton): $23.95 in 2022 and $26.70 in 2027 (Minnesota Power supplied these figures, citing the Minnesota Public Utilities Commission's Carbon Valuation Docket *(MPUC Docket Nos. E-999/CI-13-796 and E-999/CI-07-1199)*.

Penalizing CO2 production raises the marginal cost of production for gas and coal-fired power plants, approximately as shown in Table 5.1 below. The given penalties are large enough to invert the economic merit order of coal and combined-cycle units and would raise LMP correspondingly when such a generator is the marginal unit (setting the price):

**Table 5.1 – Illustrative Generator Marginal Cost with and without CO2 Penalty**

| | | With no CO2 penalty | | | | With CO2 penalty = $23.95 | | |
|---|---|---|---|---|---|---|---|---|
| | | Fuel, $/MBtu | Heat Rate (MBtu / MWh) | Variable O&M, $/MWh | **Marginal Cost, $/MWh** | lb CO2 emitted per MBtu of heat | CO2 penalty, $/MWh | **Marginal Cost, $/MWh** |
| Coal | Steam Turbine | 3 | 10.5 | 3 | **$ 35** | 209 | $ 26 | **$ 61** |
| Gas | Combined Cycle | 5 | 8 | 2 | **$ 42** | 119 | $ 11 | **$ 53** |
| | Combustion Turbine | 5 | 12 | 3 | **$ 63** | 119 | $ 17 | **$ 80** |

The installed capacity of Combined-cycle generation being about half that of coal-fired generation (see Table 2.1) and insufficient by itself to meet the higher levels of demand, coal would be expected either to be on the margin or be displaced by less expensive imported energy in higher-demand hours in the "carbon tax" sensitivity.

Based on the "typical" figures from Table 5.1, the marginal energy component of LMP (neglecting transmission congestion and loss pricing) in peak hours would be expected to rise by at least $11-18 relative to the case with no carbon penalty, from $35-42 (coal or gas CC on the margin) to $53 or more (gas CC or imports on the margin). The results of this study support this conjecture. (Refer to the "on-peak average LMP" column of Table 5.2, below.)

Table 5.2 presents the change in Minnesota LMP in the carbon sensitivity case and compares it with the Business As Usual scenario. Table 5.3 presents the change in Adjusted Production Cost.

**Table 5.2 – Locational Marginal Prices with and without CO2 Penalty**

| | | | LMP for Minnesota Load (Weighted-Average) | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Average LMP ($/MWh) | | | Change due to 500 kV GNTL line (in - out, $ / MWh) | | |
| | Scenario | GNTL status | On-peak | Off-peak | All hours | On-peak | Off-peak | All hours |
| 2022 | BAU | out | $ 38.35 | $ 25.91 | $ 31.82 | -0.08 | 0.00 | -0.04 |
| | | in | $ 38.28 | $ 25.91 | $ 31.79 | | | |
| | Carbon | out | $ 54 85 | $ 45.94 | $ 50.17 | -0.03 | 0.00 | -0.01 |
| | | in | $ 54.82 | $ 45.95 | $ 50.16 | | | |
| 2027 | BAU | out | $ 42.29 | $ 28.70 | $ 35.18 | -1.35 | -0.26 | -0.78 |
| | | in | $ 40.95 | $ 28.44 | $ 34.40 | | | |
| | Carbon | out | $ 60.62 | $ 49.62 | $ 54.87 | -1.04 | -0.04 | -0.52 |
| | | in | $ 59.57 | $ 49.58 | $ 54.35 | | | |

Adding the carbon penalty to the BAU scenario reduced the simulated impact that GNTL would have on LMP in Minnesota. LMPs are flatter across load levels, presumably because gas is on the margin more frequently. This reduces the opportunity for the hydro energy delivered by GNTL to moderate high prices that drive up average prices.

**Table 5.3 – Adjusted Production Cost with and without CO2 Penalty**

| | | | Adjusted Production Cost ($Billion) | | Change due to GNTL (in - out, $Billion) | |
|---|---|---|---|---|---|---|
| | Scenario | GNTL status | MISO | Minnesota | MISO | Minnesota |
| 2022 | BAU | out | 18.8001 | 1.6275 | -0 0004 | 0.0002 |
| | | in | 18.7996 | 1.6277 | | |
| | Carbon | out | 31.1953 | 2.8776 | 0.0010 | 0.0006 |
| | | in | 31.1963 | 2.8782 | | |
| 2027 | BAU | out | 21.9331 | 1.9494 | 0.0022 | -0.0033 |
| | | in | 21.9354 | 1.9460 | | |
| | Carbon | out | 35.5899 | 3.3205 | 0.0049 | -0.0015 |
| | | in | 35.5949 | 3.3190 | | |

Adjusted Production Cost does not change materially with the addition of a carbon penalty.

# 6 Conclusion

PROMOD LMP simulations were performed for 2022 and 2027, using input assumptions consistent with the 2013 MISO Northern Area Study. Significant amounts of wind, combined-cycle and even solar PV generation were modeled in MISO in the 2027 cases that were not present in the 2022 cases.

Input assumptions were established for two separate future scenarios (Business as Usual and High Growth) and 8,760-hour chronological simulations were performed for each scenario with the GNTL in service and without, as the only input change.

The salient result from this study is that interconnection of the 500 kV GNTL brings about:

1. decreased Locational Marginal Prices (LMPs) within Minnesota
2. no material change to the cost to serve load in MISO or Minnesota