# The Husker Power Plan: A New Energy Plan for Nebraska

**By**

**Sommer Energy, LLC**

**Anna Sommer**
**President**
**Tel. 315-386-3834**
**anna@sommerenergy.com**

**Applied Economics Clinic**

**Elizabeth A. Stanton, PhD**
**Director and Senior Economist**
**Tel. 781-819-3232**
**liz.stanton@aeclinic.org**

**Tyler Comings**
**Senior Researcher**
**Tel. 617-863-0139**
**tyler.comings@aeclinic.org**

SOMMER ENERGY, LLC

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

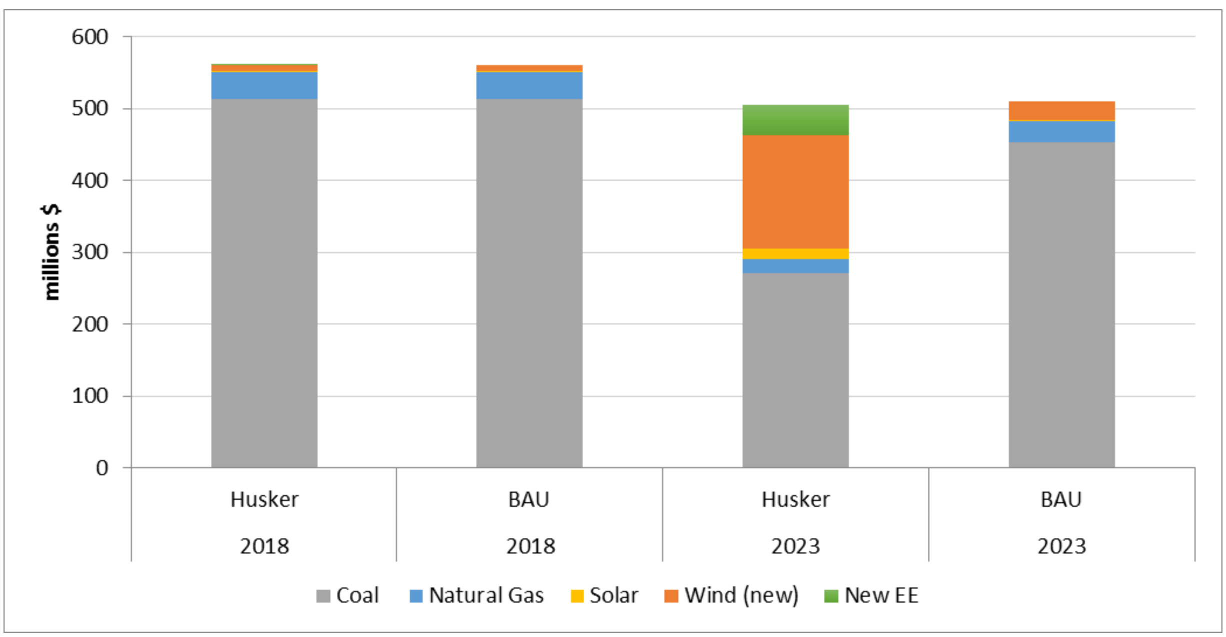
## I. Introduction and Rationale for Report

Sommer Energy, LLC and Applied Economics Clinic were asked by the Nebraska Wildlife Federation (NeWF) to produce a plan envisioning an electric grid in Nebraska that relies more heavily on cost-effective wind, solar, and energy efficiency. With the costs of wind and solar at historic lows, NeWF seeks to determine how Nebraska's expanded reliance on renewables, coupled with greater investment in energy efficiency, could reduce the overall cost of electricity in Nebraska as well as change the state's trajectory of carbon dioxide emissions.

This report compares two scenarios. Business as Usual (BAU) assumes continued operation of Nebraska's electrical system as it exists today coupled with firm capacity additions, retirements, and refueling of power plants already announced. What we call the "Husker Power Plan"—so named because it can be implemented by acquiring new resources in-state—includes higher levels of wind, solar, and energy efficiency resources than are currently planned. In the Husker Power Plan, by 2023, we add 1,500 MW of wind, 129 MW of solar PV, and reduce peak demand by 296 MW—all relative to BAU. Our analysis confirms that Nebraska can move to a much cleaner electric system by 2023 with no additional cost and indeed there is a high likelihood of lower costs.

Figure 1 shows expenditures by cost categories that vary between the Husker Power Plan and the BAU. This is not a full accounting of the cost of operating Nebraska's electrical system, but rather a comparison of the specific costs that are likely to change as wind, solar, and energy efficiency are added in the Husker Power Plan and displace coal and natural gas generation that would otherwise occur under a BAU scenario.

**Figure 1: Expenditures under the BAU and Husker Power Plan in Selected Cost Categories ($2016)**



The Husker Power Plan and the BAU scenario have essentially the same costs in 2023.[1] We calculate that Husker Power Plan would be $3.7 million ($2016) cheaper than BAU, a number that we consider to be "in the noise." For reference, we estimate that Nebraska utilities will spend just over $400 million on fuel and other variable operating expenses in 2018 alone. Our cost analysis assumes the high end of the cost range for resources like energy efficiency and solar, which are added in greater quantities in the Husker Power Plan and also does not assume retirement of any existing capacity which would reduce ongoing capital and operating expenditures. As a result, the costs of the Husker Power Plan may be overestimated.

## II. Modeling Results and Discussion

The Husker Power Plan and the BAU scenario are essentially at par in terms of cost in 2023. We calculate that Husker Power Plan would be $3.7 million ($2016) cheaper in that year, a number that we consider to be "in the noise." For reference, we estimate that Nebraska utilities will spend just over $400 million on fuel and other variable operating expenses in 2018 alone.

Our cost methodology was premised in large part on assessing the current costs of Nebraska's fleet and making adjustments as necessary. Specifically, we assumed that there would be changes in fuel costs in line with the EIA forecasts as described previously, but that maintenance costs such as fixed O&M and non-fuel variable O&M would remain unchanged in "real" terms going forward (i.e. increase at the rate of inflation).

While there is relatively little difference in cost between the two plans by the end of our study period, there are significant differences in key cost categories. These include amounts spent on:

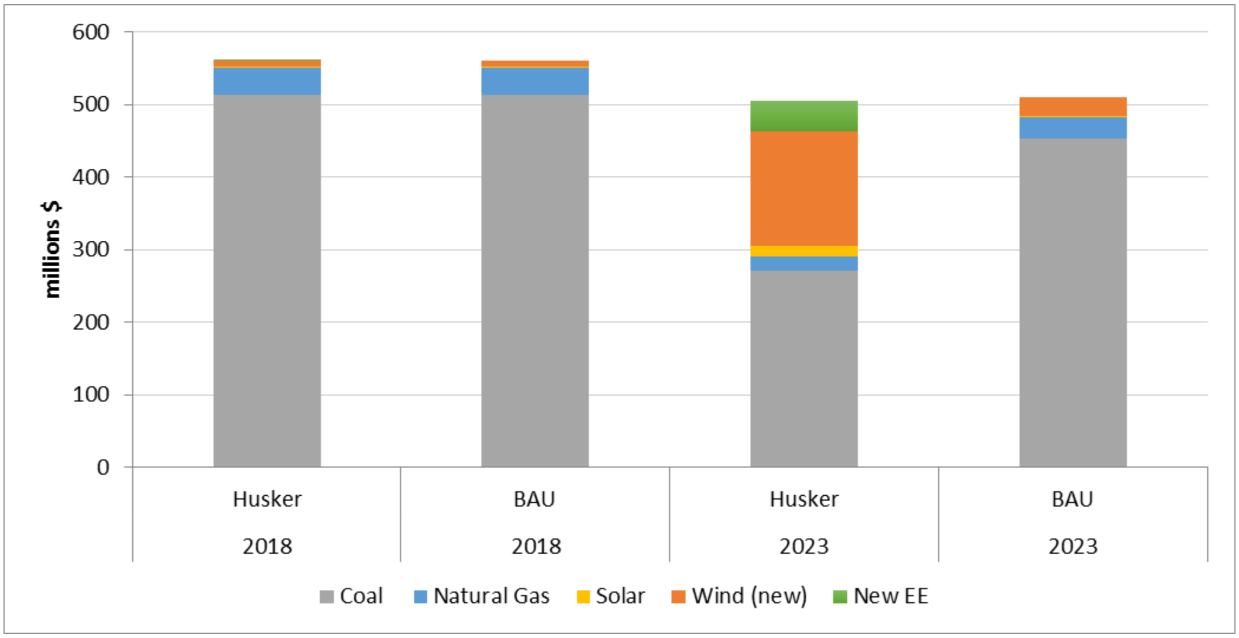
1. Coal-related generation,
2. Natural gas-related generation,
3. Wind-related generation,
4. Solar-related generation,
5. And energy efficiency.

In our first snapshot year of 2018, the costs of the two plans are largely consistent since they differ only in the Husker Power Plan's slightly elevated rate of energy efficiency expenditures and therefore slightly decreased coal expenditures.

However, by 2023, expenditures on coal are significantly changed under the Husker Power Plan and are largely replaced by expenditures on wind and secondarily, energy efficiency.

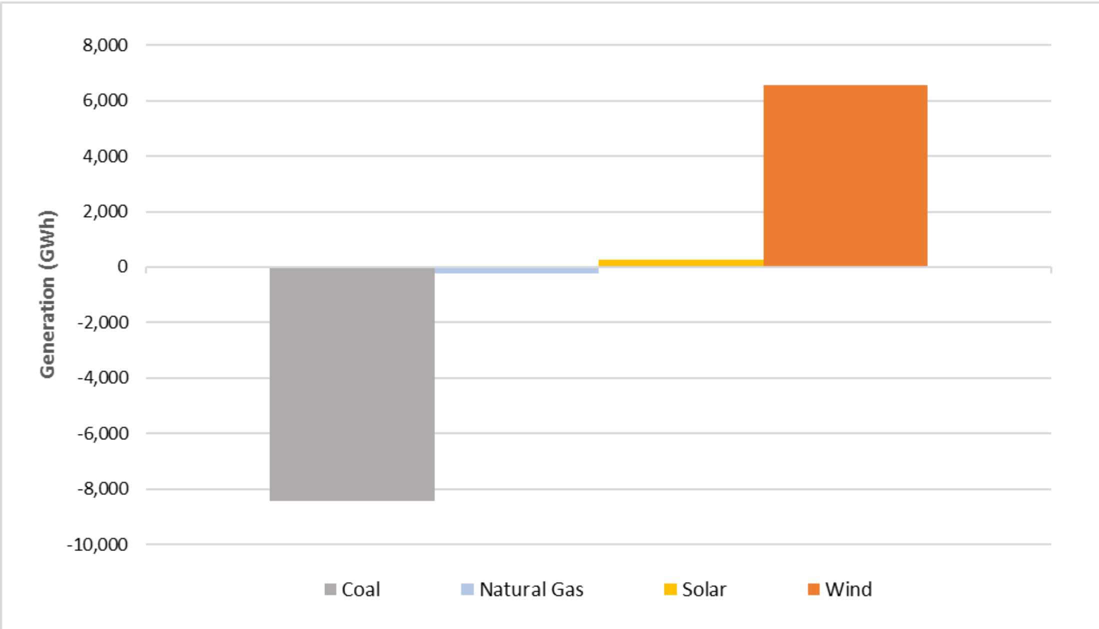
[1] The cost estimates contained in this report are not intended to capture the total cost of the electrical system in Nebraska. For example, "sunk" costs like capital expenditures that have already been incurred for existing generators, but are still being paid off by customers, are not included nor are they generally publicly available. For that reason we focus on cost savings among those categories of costs that can and are likely to change between the BAU and Husker Power Plan scenarios.

**Figure 2: Expenditures under the BAU and Husker Power Plans in Selected Cost Categories**




As shown above, the additions of energy efficiency, wind, and solar in the Husker Power Plan change the performance of existing resources serving Nebraska. Coal and natural gas are relied upon less often in the Husker Power Plan due to additional energy efficiency and renewable energy. Once these cleaner resources are in-place, they cost very little to operate and thus will result in reducing operations of fossil generators. Figure 3 below shows the change in 2023 generation from the Husker Power Plan when compared to BAU.

**Figure 3: Change in 2023 Generation by Resource Type with Husker Plan (GWh)**




By 2023, solar PV produces 249 GWh more in the Husker Power Plan based on an assumed 22 percent capacity factor for new installations. At the same time, the equivalent amount of natural gas generation is reduced. Natural gas steam and combustion turbines in Nebraska are typically called upon during peak times. These units only run 3 percent of the time, historically (see Table 4). If the state has more solar PV on its system, then it will call upon natural gas units even less frequently.

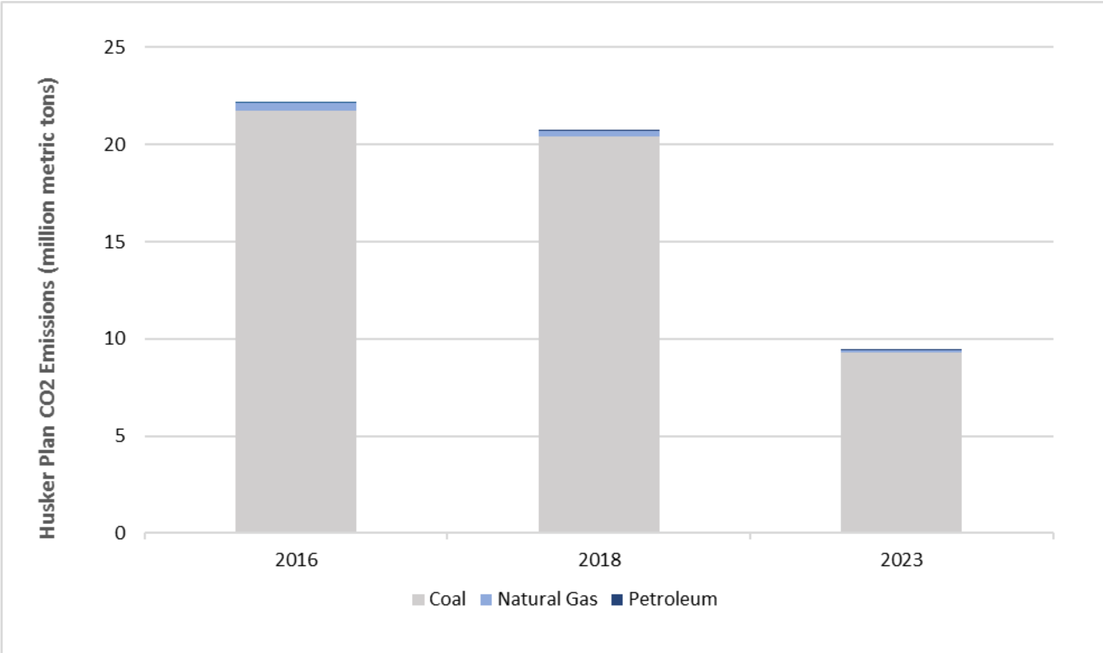
Likewise, wind and energy efficiency displace coal generation. Coal is by far the largest source of generation in the state. Some units operate more often than others but on the whole, coal units operate more than half the time that they are available. Nuclear is the next largest source of generation in the state but tends to run for days or weeks at a time. Thus, wind and efficiency will likely displace coal generation on the system. New wind is expected to produce an additional 6,570 GWh, assuming a 50 percent capacity factor for new installations. Energy efficiency reduces coal generation serving Nebraska by 1,852 GWh by 2023. Wind generation displaces coal one-for-one. However, because energy efficiency avoids transmission and distribution line losses, one unit of saved energy avoids more than one generated at a coal unit.[2]

*Emissions under the BAU and Husker Power Plan*

The total power sector emissions from the Husker Power Plan are under 10 million metric tons by 2023—shown below in Figure 4. This represents a 57 percent reduction in carbon emissions from 2016 to 2023. Nearly all of this reduction comes from the displacement of coal with new wind, solar PV, and energy efficiency added in the Husker Plan.

[2] We assumed 4.38% line losses based on the four-year average provided by the EIA's "Supply and Disposition of Electricity" report for Nebraska (https://www.eia.gov/electricity/state/nebraska/index.php)

**Figure 4: Carbon Dioxide Emissions in Husker Plan ('000 metric tons)[3]**




In sum, the Husker Power Plan outlines a pathway for Nebraska to achieve a significant reduction in carbon dioxide emissions at comparable to lower cost.

## III. Methodology and Assumptions

For purposes of this report, we developed an annual time-scale spreadsheet model of Nebraska's electric system that covers all electric load served by Nebraska Public Power District (NPPD), Omaha Public Power District (OPPD), Lincoln Electric System (LES), Grand Island Utilities, Fremont Utilities, Hastings Utilities, Tri-State Generation, and Municipal Energy Agency of Nebraska (MEAN). The boundary of our analysis is the consumption of electricity in Nebraska rather than what is generated within the state's borders. This means that we include generators outside of the state that serve Nebraska ratepayers and, conversely, we exclude the portions of in-state generators that serve ratepayers outside of Nebraska.

We included the portions of Laramie River (located in Wyoming) and Walter Scott, Jr. Energy Center (located in Iowa) owned by LES.[4] We also included two out-of-state wind farms that serve Nebraska: Arbuckle Mountain Wind Project and Buckeye Wind Project. We excluded the portions of the Nebraska City plant and Whelan Energy Center that are co-owned by utilities outside of Nebraska. Tri-State does not tie its power plants to specific customers but the purchase of generic capacity and energy to serve Nebraska is accounted for here—as in the Nebraska Power Association (NPA) report.

[3] 2016 emissions from EIA 923 data.
[4] See: https://www.les.com/about-les/facilities

Our study covers the period of 2018 through 2023, with data for the first and last year shown as "snapshots" in this report. We also show actual cost, generation, and other information for 2016 as a point of comparison to many of our projections. Certain metrics, like power plant maintenance costs, were projected using historical data from 2012 through 2016.

*Determining Demand and Energy Sales*

A key constraint that must be satisfied by all Nebraska utilities is the reserve margin requirement. As members of Southwest Power Pool (SPP) Regional Transmission Organization (RTO), utilities in Nebraska must maintain at least a 12 percent reserve margin, that is, capacity resources 12 percent over and above their peak load. Our study relies on the 2017 Nebraska Power Association Load and Capability Report for forecasts of peak load and summer capacity credit assigned to generators that serve Nebraska. It is unclear, though likely, that future energy efficiency savings are embedded in the NPA 2017 peak load forecast.[5] In 2016, Nebraska incrementally saved 0.19 percent of electricity sales.[6] We assume this is already embedded in the BAU, thus there is minimal efficiency savings included in that scenario. The 2017 NPA report showed a 2 percent increase in load for the study period: 7,044 MW in 2016 to 7,200 MW in 2023.

The Husker Power Plan included a reduction in peak load based on energy efficiency savings beyond business as usual (described below). While energy efficiency measures are intended to reduce everyday usage, they also reduce peak load for the system. We applied a peak reduction factor of 0.00017 kW for every kWh of energy saved in the Husker Power Plan.[7] This leads to a 2 percent reduction in peak load from 2016 to 2023 (7,044 to 6,904 MW) due to incremental energy efficiency described below. As shown in Table 1, by 2023 the Husker Power Plan demand is 296 MW lower than in the BAU.

**Table 1: Peak Load in BAU and Husker Power Plan (MW)**

| Peak load (MW) | BAU | Husker Power Plan | Difference |
|---|---|---|---|
| 2016 | 7,044 | 7,044 | 0 |
| 2018 | 7,147 | 7,134 | -13 |
| 2023 | 7,200 | 6,904 | -296 |
| **% change 2016 to 2023** | 2% | -2% | -4% |

[5] *2017 Nebraska Power Association Load and Capability Report*
[6] ACEEE 2017 Efficiency Scorecard, available at: http://aceee.org/state-policy/scorecard
[7] This ratio is typical of utility-sponsored energy efficiency programs.

Retail sales in Nebraska are reported to the U.S. Energy Information Administration (EIA) for each utility in the state.[8] Going forward, for the BAU, we assumed that the percentage change in peak load matched the percentage change in projected sales.

In the Husker Power Plan, we assume an increasing level of savings through 2023 at which time the total savings from utility efforts would be 2 percent incremental savings per year. This means that the implementation of new energy efficiency measures in 2023 would save 2 percent of that year's total energy sales. This level has been achieved by several states in the United States already. (Nebraska is currently ranked 44th in the United States by ACEEE in terms of overall energy efficiency.[9]) This additional savings ramps up to its full level by 2023. This leads to a 4 percent decrease in energy consumption in the Husker Power Plan in 2023 or a total of 1,775 GWh fewer energy sales than in the BAU.

**Table 2: Energy Sales in BAU and Husker Power Plan (MW)**

| Energy Sales (GWh) | BAU | Husker Power Plan | Difference |
|---|---|---|---|
| 2016 | 29,839 | 29,839 | 0 |
| 2018 | 30,276 | 30,200 | -76 |
| 2023 | 30,500 | 28,725 | -1,775 |
| % change 2016 to 2023 | 2% | -4% | -6% |

Additional energy efficiency in the Husker Power Plan is assumed to displace coal generation. For every MWh of incremental savings, coal is expected to operate 1.05 MWh less—due to the fact that every MWh of energy efficiency reduces both the need to generate power as well the transmission loss associated with bringing that power to customers. Thus, energy efficiency is a key contributor to carbon emissions reduction in the Husker Power Plan.

*Resource Costs*

It does not appear that Nebraska needs to add any new capacity during the study period, which means that both the BAU and the Husker Power Plan would meet SPP's 12 percent reserve margin requirement. Nebraska's utilities currently have a surplus of capacity available over what they need to meet their reserve margin requirements. Because of this, the only supply-side resources we propose to add are wind and solar. Nebraska has so much excess capacity at present that we did not contemplate the addition of resources that would primarily serve capacity or peak supply needs like battery storage.

[8] EIA 826, Sales to Ultimate Customers (Megawatt hours) by State by Sector by Provider 2016
[9] See: https://database.aceee.org/state/nebraska

Our cost and operational assumptions for wind and solar are given in the table below.

**Table 3: Costs of New Energy Resources**[10]

| Technology | Capacity Factor | Capital Cost (2016$) | Levelized Cost over 20 years (2016$ per MWh) |
|---|---|---|---|
| Solar | 22% | $1,300/kW | $51 |
| Wind | 50% | $1,500/kW | $20 |
| Gas CC* | 48% | $1,000/kW | $40-$70 |

*Note that since we did not include new gas CCs in either scenarios we are simply providing this information for comparison purposes.

We assume that energy efficiency has a first-year cost of $0.20 per kWh. First year cost is derived by taking the cost of achieving incremental energy savings in any given year divided by the incremental kWh savings achieved in that year. In our experience, this is on the high end of the range for other utilities. It is entirely possible that Nebraska could acquire energy efficiency at a much lower first year cost. However, since the energy efficiency goal that Nebraska would ultimately achieve under the Husker Power Plan is much higher than its current level of savings we felt it best to estimate costs on the high end of the range.

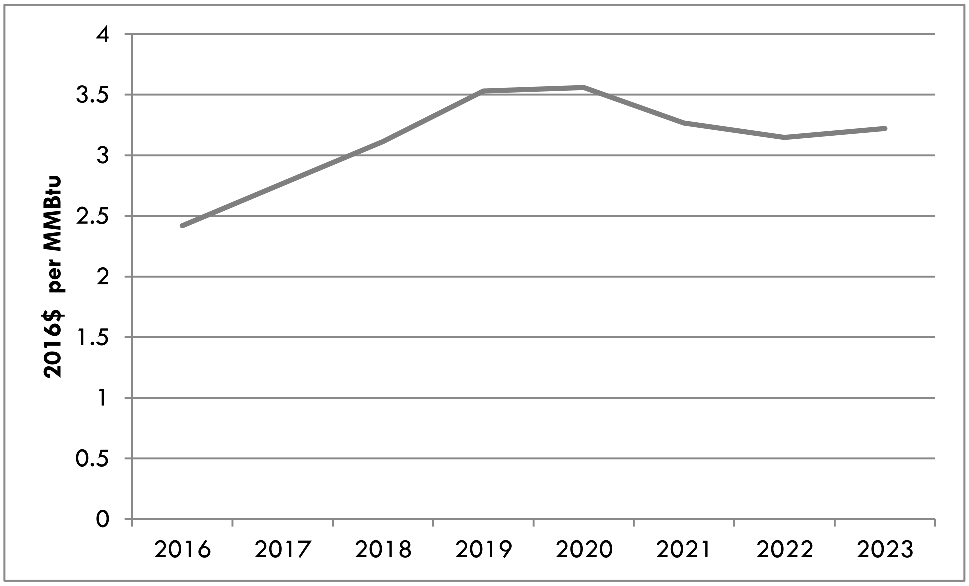
We relied on one of the EIA's 2017 Annual Energy Outlook (AEO) low price forecasts of Henry Hub prices.[11] We chose this instead of the "reference case" forecast because it is more in-line with EIA's most recent short-term energy outlook and natural gas market forwards.[12] Projected annual natural gas prices are shown in Figure 5.

[10] The sources for this information are National Renewable Energy Laboratory, Lawrence Berkeley National Laboratory, Lazard (https://www.lazard.com/perspective/levelized-cost-of-energy-2017/), and NPPD's 2013 Integrated Resource Plan.

[11] EIA, 2017 Annual Energy Outlook, "High oil and gas resource technology" case (https://www.eia.gov/outlooks/aeo/)

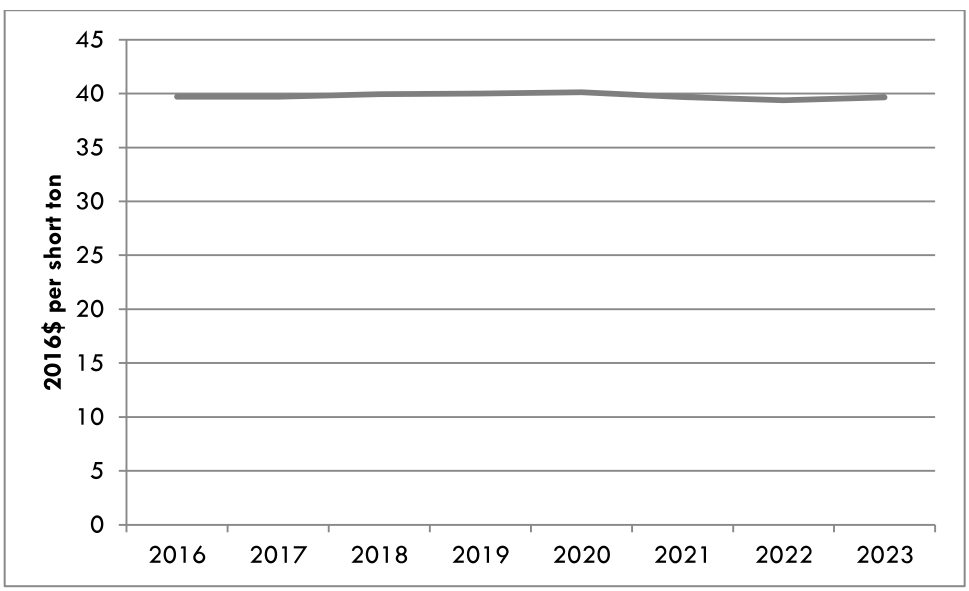
[12] EIA Short-Term Energy Outlook (STEO) (https://www.eia.gov/outlooks/steo/index.cfm) and NYMEX market futures (For example, see: http://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_settlements_futures.html#tradeDate=12/04/2017)

**Figure 5: EIA Natural Gas Price Forecast ($2016/MMBtu)**




We relied on the EIA's 2017 Annual Energy Outlook (AEO) forecast of regional coal prices.[13] The annual minemouth prices for low sulfur coal coming out of the Powder River Basin are shown below. We added a transportation cost based on an analysis of costs incurred by coal-fired power plants serving Nebraska customers from 2012 – 2016. Transport costs were assumed to range between $7.62 and $11.34 per MWh depending on the power plant in question. Projected annual coal prices, without transport costs, are shown in Figure 6.

**Figure 6: Coal Price Forecast ($2016/short ton)**




[13] EIA, 2017 Annual Energy Outlook, (https://www.eia.gov/outlooks/aeo/)

*Forecasting the Performance of Supply-Side Units*

The recent performance of existing generation (shown below) is assumed to persist in the future for BAU. Table 4 below shows capacity factors by resource type. This measures how much each type of resource generates relative to their maximum potential. In the Husker Power Plan, generation from coal and natural gas is reduced with the addition of energy efficiency and new renewable resources (described in further detail in the next section). Thus, in the Husker Power Plan, coal and natural gas operate less often than they would in BAU (which draws power only from existing resources). Under both scenarios, the amount of power imported and exported was assumed to be fixed.

**Table 4: Capacity Factor by Resource Type (%)**[14]

| Resource | 2016 Capacity Factor (%) | 2023 BAU Capacity Factor (%) | 2023 Husker Power Plan Capacity Factor (%) |
|---|---|---|---|
| Coal | 58% | 58% | 30% |
| Hydro | 71% | 71% | 71% |
| Natural Gas | 3% | 3% | 1% |
| Nuclear | 88% | 88% | 88% |
| Landfill Gas | 56% | 56% | 56% |
| Biomass (Commercial CHP) | 41% | 41% | 41% |
| Petroleum | 0.2% | 0.2% | 0% |
| Hydrogen | - | 90% | 90% |
| Solar | - | 22% | 22% |
| Wind (existing) | 34% | 34% | 34% |
| Wind (new) | - | 50% | 50% |

*Building the BAU and Husker Power Plan*

Both the BAU and Husker Power Plan scenarios resulted in surplus capacity, i.e. over and above what is required for planning purposes by the Southwest Power Pool. The BAU scenario had a 16 percent reserve margin in 2023 and the Husker Power Plan 25 percent. Due to peak load reduction and added capacity (discussed later), the Husker Power Plan has 735 MW of capacity surplus compared to 251 MW in the BAU. This means there is 485 MW of incremental surplus in the Husker Power Plan and, therefore, there would be plenty of room for the state to retire some of its aging and/or expensive capacity.

[14] EIA 923 data.

SPP currently requires a “reserve margin” of 12 percent over and above peak load. There does not appear to be any discount for coincidence with the SPP system peak,[15] so we applied this percentage to the Nebraska summer peak without adjustment. To calculate Nebraska’s reserve margin, we used the 2017 NPA report’s values for summer capacity credit[16] for existing resources—where available. By 2023, the Husker Power Plan has 153 MW more accredited supply-side capacity than the BAU. The Husker Plan also reduces peak load by 296 MW which reduces the reserve requirement by 332 MW (including a 12 percent reserve margin). Combined with the 153 MW of additional summer capacity, this results in the 485 MW of capacity surplus, relative to the BAU. This assumes no additional retirements of generation in the Husker Power Plan. It is solely based on the capacity credit applied to the new wind and solar resources that are not also built in the BAU.

The table below shows the existing resources by fuel type in the state.

[15] Other RTOs will apply a “coincidence factor” to a utility’s peak demand to account for the fact that the utility’s peak demand is unlikely to occur at exactly the same time as the RTO-wide peak demand.

[16] Generators’ capacity credit is meant to represent how available they are at peak times. Because wind and solar are intermittent and non-dispatchable, only a portion of their installed capacity counts towards Nebraska’s summer capacity. For new wind, we assumed that a 5 percent capacity credit is applied in the first three years—based on SPP rules. After three years, wind farms’ capacity credit is based on actual performance. We assumed that this credit will be 15 percent, based on the capacity credits assigned to wind farms operating for more than three years—shown in the 2017 NPA report. For solar, we applied a 10 percent capacity credit for the first three years (again, based on SPP rules) and a 15 percent credit in subsequent years. The latter figure is likely conservative, however, unlike with wind, there is no data available on actual capacity credit for solar projects more than three years old.

**Table 5: Existing Capacity (MW)**

| Resource | 2016 Capacity (MW) |
|---|---|
| Coal | 4,137 |
| Hydro | 278 |
| Natural Gas | 2,040 |
| Nuclear | 1,250 |
| Landfill Gas | 11 |
| Biomass (Commercial CHP) | 5 |
| Petroleum | 302 |
| Solar | 7 |
| Wind | 1,530 |

Current levels of distributed generation are low. According to the EIA, in 2015 there were zero MW of distributed solar installed in Nebraska. While the actual number is not zero, it is likely negligible when compared with Nebraska's energy system. According to the 2016 NPA report, there are 8.8 MW of distributed wind projects currently in the state. While there are more such projects pending, these should already be included (as "behind the meter") in the forecast of energy demand provided in that report. We did not make any assumptions of additional "behind the meter" generation above what is already planned in the BAU. We also did not address combined heat and power (CHP) since the design and cost of such projects is likely specific to the location or industry to which it applies.

In 2014, OPPD announced a goal of pursuing 300 MW of total peak load reduction from both energy efficiency and demand response. We assumed that this goal was already captured in the data reported in the Nebraska Load and Capability report. Similarly, we assumed that NPPD's 600 to 650 MW of irrigation load demand (DR) capability was accounted for in that report.

With respect to the need for major new transmission lines to accommodate new renewables, the main guidance on this topic is the LB 1115 study performed by the Brattle Group for the Nebraska Power Review Board in December 2014. In that study, the authors concluded that "Based on our review of SPP studies, we find that the existing transmission system in Nebraska, including transmission additions already approved or under construction, will likely allow for the integration of at least 2,000 MW of additional renewable generating resources in Nebraska once the currently approved facilities are placed into service from 2016 to 2018."[17] That additional 2,000 MW was over and above planned renewable additions for the 2016 to 2018 period. Our proposal for the Husker Power Plan falls just short of that 2,000 MW threshold with 1,629 MW of

[17] Brattle's report is available at: http://www.powerreviewboard.nebraska.gov/PDFs/2014_NE_Renewable_Energy_Export_Study.pdf

new wind and solar by 2023. As per Brattle Group's study, the construction of the "R" transmission line project would be necessary to site these resources in Nebraska. It is worth noting, however, that, to our knowledge Nebraska lacks a comprehensive transmission needs assessment that is based on power flow modeling. Comprehensive modeling of the SPP transmission system would help identify the best locations for the new wind and solar resources contained in the Husker Power Plan.

In the BAU and Husker Power Plans, we account for planned retirements and additions in Nebraska, including:

- Conversion of Sheldon Unit 2 (120 MW) from coal to hydrogen in 2019
- Conversion of North Omaha Units 1, 2, and 3 (291 MW) from coal to natural gas in 2016
- Conversion of North Omaha Units 4 and 5 (353 MW) from coal to natural gas in 2023
- Retirement of Fort Calhoun nuclear station (502 MW) in late 2016[18]

In the Husker Power Plan, we are nearly doubling the amount of wind in Nebraska by 2023—an additional 1,500 MW above what is in the BAU. We are also proposing to add 26 MW of new solar every year starting in 2019—leading to 129 MW of cumulative new solar by 2023. The current amount of solar in Nebraska is 7 MW. We assume additions of 23 MW in the BAU through 2023. Finally, in the Husker Power Plan we assume an additional 1.81 percent, over what Nebraska currently achieves, of utility-sponsored, incremental energy efficiency savings per year by 2023. All of these changes—along with planned additions and retirements in the BAU—would leave Nebraska with a large capacity surplus of 741 MW in 2023. This means that the Husker Power Plan could include over 700 MW of currently unplanned retirements and remain resource-adequate.

## IV. Areas for Further Analysis

Snapshot, spreadsheet-based analyses like that underlying this report, can be useful to outline big picture differences between competing visions of any electrical system. We do recognize, however, that more detailed analyses at the utility level would be necessary to develop a plan to actually implement the path outlined in the Husker Power Plan. Those analyses would likely require power dispatch models and even power flow models that were not available to us as part of this report. Without access to the detailed, costly, and often proprietary, models used by utilities, our spreadsheet model was a necessary simplification of Nebraska's electric system.

Because Nebraska is part of the Southwest Power Pool, its generators are dispatched not just to serve demand within Nebraska, but to serve demand throughout the SPP system. By the same token, other generators outside of Nebraska, but still within SPP, are also serving Nebraskans. Adding resources with low to no marginal costs of operation like energy efficiency, wind, and solar will almost certainly cause coal and natural gas-fired power plants to generate less in SPP, but it is difficult to predict whether those power plants would be located in Nebraska or

[18] Capacity from Fort Calhoun was included in 2016 as it was available during that summer peak period.

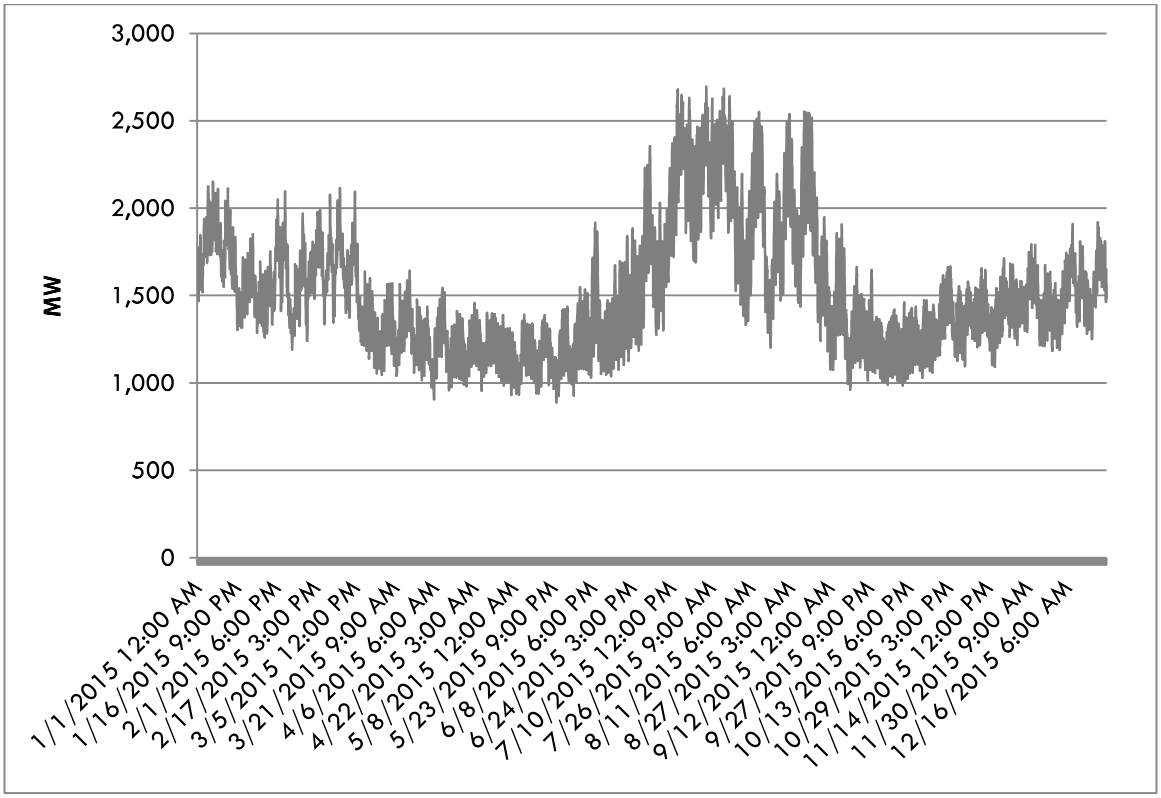
elsewhere in SPP without the use of detailed dispatch modeling. Therefore, the carbon dioxide emissions reductions predicted by our spreadsheet model could come not just from Nebraska power plants, but also power plants outside of Nebraska.

Similarly, because load in Nebraska is served by all power plants within SPP, the reduction in gas and coal costs that come in the Husker Power Plan from the addition of energy efficiency, wind, and solar, are partially proxies for what would be the changing costs to serve load through SPP. Using Nebraska's owned and contracted generators as stand-ins for these costs is reasonable because Nebraska's power plants are not out of line with the costs of other, similar power plants.

Further analysis could also identify cost savings from the Husker Power Plan that could not be captured in our study. As discussed in Section III, the Husker Power Plan leaves ample room for retirement of existing, more expensive capacity. That capacity almost certainly has a set of ongoing capital expenditures associated with it that are being paid by Nebraskan ratepayers through their utility rates. With retirement, those capital expenditures can be avoided. These types of cost savings were not part of our study because plant-specific capital expenditure schedules are not made public. These types of expenditures could include turbine upgrades, pollution control additions/upgrades, etc. and are highly specific to the power plant in question.

Finally, we noted a seasonal pattern of electricity consumption in Nebraska that is unusual. As an example, in Figure 7, the load curve created by summing all hours of the 2015 demand of Nebraska Public Power District's customers shows an extreme peak in the summer time relative to the spring and fall seasons with a smaller, secondary peak occurring in the wintertime.

**Figure 7: 2015 NPPD Demand Curve**[19]




The summertime peak is likely caused by pumping for irrigation and air conditioning. Thus Nebraska can further reduce its peak demand—and therefore its reserve margin requirement—by more aggressively promoting irrigation-related demand response, more energy efficiency, and air conditioning demand response. It was well outside the scope of this study to attempt to quantify the impacts and costs of undertaking these efforts, but smoothing out Nebraska's demand curve would almost certainly reduce system-wide costs because it would eliminate the need to hold on to more expensive generation merely for the purpose of meeting peak load.

[19] From FERC Form 714.