**Black Hills Colorado Electric, LLC**
**2026 Rule 3627 Report – Appendix N – Black Hills Supporting Documents**

# Appendix N

### 1.1.1. Black Hills Supporting Documents

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# Black Hills Energy OATT Attachment K

Black Hills' Transmission Planning Process is included in the OATT as Attachment K. This document is available at the following link: Attachment K, Transmission Planning Process

# Black Hills Energy OATT Attachment K Business Practice

Black Hills' Attachment K Business Practice Manual is available at the following link: Attachment K Business Practice Manual

# Black Hills Energy Transmission System Planning Methodology, Criteria and Process Business Practice

Black Hills' Transmission System Planning Methodology, Criteria and Process Business Practice Manual is available at the following link: Transmission System Planning Methodology

# Black Hills Energy Available Transfer Capability Implementation Document (ATCID)

Black Hills' Available Transfer Capability Implementation Document is available at the following link: ATCID

# Black Hills Energy Transmission Reliability Margin Implementation Document (TRMID)

Black Hills' Transmission Reliability Margin Implementation Document is available at the following link: TRMID

# Black Hills Energy Capacity Benefit Margin Implementation Document (CBMID)

Black Hills' Capacity Benefit Margin Implementation Document is available at the following link:
CBMID

# Black Hills Energy Economic Planning Study Request Form

## Transmission Provider Economic Planning Study Request Form

Stakeholders may request Transmission Provider to perform a high-priority Economic Planning Study. All such requests must satisfy the criteria.

1 All requests for high priority Economic Planning Studies must be submitted to Transmission Provider in writing signed by the stakeholder making the request.

2 The written request must set forth, in detail and consistent with FERC policy, why a High-Priority Economic Study is justified. The justification should address all relevant facts that indicate that the study is "… for the purposes of planning for the alleviation of congestion through integration of new supply and demand resource into the regional transmission grid or expand the regional transmission grid in a manner that can benefit large numbers of customers, such as by evaluating transmission upgrades necessary to connect major new areas of generation resource (such as areas that support substantial wind generation). Specific requests for service would continue to be studied pursuant to existing pro forma OATT processes."[1]

3 This letter also must include, at a minimum the following information.

- 3.1 Contact Information including the name of sponsor, business address, mailing address, email address and phone number.
- 3.2 A statement that the request is not a request for single transmission service request or generation interconnection request.
- 3.3 A defined point of receipt and point of delivery are defined.
- 3.4 A defined monthly or hourly MW amount.
- 3.5 A defined monthly energy in KWh.
- 3.6 If the requestor's own generation is affected by the request, the following information must be provided: economic dispatch costs, hourly generation patterns, relevant maintenance information; expected generation forced outage rate; and all other factors affecting generation output.
- 3.7 If the requestor's own load is affected by the request, then the expected change in hourly load profile must be provided.
- 3.8 If the request involves or affects third party generation or load, all public information for this third party generation or load (as described in 3.2-3.7) in possession of the requestor must be provided.

4 A statement that the requestor will provide, to the greatest extent practical, additional information and agrees to cooperate with Transmission Provider as necessary to complete the economic study.

5 Sponsors of the Economic Study Request are invited to participate in Transmission Provider's open TCPC meeting where prioritization will be discussed.

[1] **Paragraph 549, FERC Order 890, OATT Reform.**

**BHCT_Economic_Planning_Study_Request_Form – Revised: 3-3-11**

# Black Hills Energy 2023 ERP Load Forecast
# Attachment LS-1, Section 4

## Load Forecast

The starting point for ERP modeling and analysis is an annual peak and energy load forecast. This forecast, based on realistic assumptions about local population changes and local economic factors, determines the future demand the utility's resources will be required to meet.

The Plan employs an econometric forecasting methodology to forecast peak demand and energy. The Company gathered and refined a variety of different types of datasets, including historical load, economic, and weather data. This data was used to develop models for the monthly peak demand forecast and energy forecasts.

The final system-level monthly peak demand forecast was computed by adding large customer loads, including anticipated future load growth, the effects of DSM plans, and a net behind-the-meter ("BTM") solar forecast to the base load forecast produced from the regression analysis. The final system-level major customer class energy forecasts were computed by adding large customer loads, including their anticipated future load growth, losses, the effects of DSM plans, and a net BTM solar forecast to the base energy forecasts calculated through the regression analysis.

The Plan developed base, low, high, and increased electrification load forecasts, and includes system-level demand and major customer class energy forecasts using historical data.

### 4.1 Econometric Model Overview

Econometric modeling was used as the foundation for system level demand and major customer class energy forecasts. The econometric models were developed using the statistical software package Stata®. Black Hills used this software to develop statistical models that estimate the effect of various factors (e.g., weather) on customer sales, the number of customers served, and system peak demand. The explanatory factors used in these equations consist of weather, demographic variables, and economic variables.

The advantages of econometric forecasting models include:

- The ability to estimate effects of specific drivers on sales and demand, controlling for the effect of all other included variables. For example, the models estimate the effect of economic conditions on sales controlling for variations in weather conditions.
- The ability to refine and adapt the models to reflect changing circumstances over time.
- The use of third-party weather, economic, and demographic data in the forecast removes potential concerns about biased inputs.
- Providing measures of the statistical precision of the estimates, such as the statistical significance of particular driver variables or the overall explanatory power of the forecast model.

Econometric forecasting models reveal relationships between sales (or demand or the number of customers served) and economic or demographic variables to forecast future developments. The process begins by estimating the historical relationship between sales (or demand or the number of customers served) and the relevant drivers, which may include weather, economic conditions, demographic trends, or seasonal patterns. The resulting estimates of the relationship between each driver and the associated outcome (e.g., sales) are then applied to forecasts of the drivers to develop the forecast sales, demand, or number of customers served. The statistical models are reviewed and refined to ensure that the estimated relationships are reasonable (i.e., correctly signed and of reasonable magnitude).

### 4.2 Load, Economic, and Weather Data

As noted above, the Company uses historical load data (including information on large customers), economic data, and weather data as principal inputs into its load modeling. These data inputs are discussed in more detail below.

#### 4.2.1 Historical Load Data

The Plan utilizes historical system-level hourly load data to develop the peak demand forecast. The Company identified one individual large customer whose load was removed from the historical load data before modeling. The Company excluded this customer's load from the historical data because it is a significant percentage of the Company's total load and is not expected to increase. Therefore, the Company did not want the growth rates calculated through the regression analysis applied to this large load. Black Hills subtracted this large customer's hourly peak data from the system historical data, creating a new "base" historical dataset. This "base" historical dataset was used in the regression analysis. The excluded data for the one large customer was added back into the demand forecast after the model runs were complete. Similarly, historical net BTM solar load was removed prior to modeling and was added back into the demand forecast after the model runs were complete.

The major customer class energy forecasts were developed using historic sales and customer count. Sales data by rate identification were gathered, reviewed, and aggregated into major customer classes based on the type of service (for example, residential, commercial, and industrial) as appropriate. Similar to the hourly load data, a base historical sales dataset was established by removing specific large customers and historical net BTM solar data. In addition, historical lighting service data and Company-usage data were removed before conducting the sales forecast regression analysis to ensure the customer class sales growth rates were not skewed by the historical growth patterns for these sectors. The excluded data for certain large customers, BTM solar load, lighting, and Company use were added to the aggregated sales forecast after the major class forecast regressions were complete.

The historical load and sales data used in the peak demand and sales models is included in Schedule B-1 and Schedule B-2, Appendix B, respectively.

### 4.2.2 Economic Data

Economic and demographic historical and forecast data were obtained from Woods & Poole Economics, Inc. ("W&P") for Pueblo and Fremont Counties for the years 1969 through 2050. Though this dataset includes a variety of economic variables, Black Hills determined that the relevant variables for the Company's load forecasts were persons per household, number of households, real household total personal income, total employment, gross regional product ("GRP"), and total personal income per-capita. Each of these variables was tested in the regression analysis.

The historical and forecasted economic data used in the peak demand and sales models are included in Schedule B-3, Appendix B.

### 4.2.3 Weather Data

Historical weather data was collected from the NOAA National Climatic Data Center's ("NCDC") Pueblo Airport weather station. The historical hourly temperature data was used to calculate heating degree days ("HDD") and cooling degree days ("CDD") using a 60 degree Fahrenheit threshold. The heating degree hours ("HDH") and cooling degree hours ("CDH") were calculated using 50 degree and 70 degree Fahrenheit thresholds, respectively. The HDD, CDD, HDH, and CDH data were used for both historical and normal weather forecasting purposes. The monthly CDD daily average was based upon the monthly average of total CDD; similarly, the monthly HDD daily average was based upon the monthly average of total HDD. The historical weather data used in the peak demand and sales models is included in Schedule B-4 and Schedule B-5, Appendix B respectively.

### 4.2.4 Normal Weather Conditions

The weather variables in the energy and demand forecasts are set to reflect "normal" conditions, which is interpreted as the average weather conditions over 20 years. In the energy model, the average of the sum of the cooling degree days over the available time period was used to calculate normal weather for each month. In the peak demand model, each month is determined to be either a predominantly cooling- or heating-peak month, and then only the relevant peak-hours for each month and year are averaged. Those averages are averaged again for each month and used as normalized peak weather conditions.

## 4.3 Forecast Methodology

Multiple combinations of the variables described above were tested in the development of the energy and demand forecasts. The models were refined to ensure that the estimates were logically reasonable (e.g., sales increase with CDDs) and statistically significant (or approaching statistical significance). Normal weather conditions are used to forecast energy and demand.
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### 4.3.1 Peak Demand Forecast Methodology

The Company's system demand forecast is a system-level forecast inclusive of residential, commercial, industrial, and lighting sectors. Each month's peak hours from 2006 to 2020 were used to model the monthly peak demand forecast. The peak demand model was estimated using Ordinary Least Squares ("OLS"). The resulting estimates were used in combination with normal weather and forecasted economic conditions to forecast peak demands.

Summaries of the final equations, historical and forecasted values of variables used, and resulting forecasts for the demand model are provided in Schedules B-6 through B-9, Appendix B.

### 4.3.2 Energy Forecast Methodology

To complete the energy forecast, the Black Hills system was disaggregated into four major customer classes: residential, commercial small general service, commercial large general service, and industrial large power service. The residential customer class is an aggregation of all of Black Hills' residential rate identifications ("rate IDs"). The commercial classes include Black Hills' small and large general service rate IDs, and the Company's large power service rate IDs constitute the industrial class.

Summaries of the final equations, historical and forecasted values of variables used, and resulting forecasts for the energy models are provided in Schedules B-8 through B-25, Appendix B

### 4.3.3 Solar Distributed Generation

Net BTM solar amounts represent the forecasted customer's total usage less the customer's generated solar. To complete the net BTM solar demand forecast, a piece-wise growth rate was calculated using 2014-2020 historical hourly net BTM data, the Company's system load shape, and anticipated growth of future ITC adoption rates. This growth rate was applied to the previously excluded solar demand data to forecast forward.

To complete the net BTM solar energy forecast, previously excluded solar load was used to develop customer count and class-level UPC forecasts. The residential, small general service, and large general service customer models were estimated using a traditional OLS approach, similar to the base energy forecast. The class-level UPC models were estimated using historical growth rate trends from 2006 through 2020. The customer count and UPC forecasts were multiplied together to produce the annual net-meter solar energy forecasts. These forecasts are then allocated across the 12 monthly periods in line with the expected solar irradiation levels across the geographic service territory. The Large Power Service net-meter solar energy forecast was produced by holding 2020 actual energy levels constant.

A detailed summary of the net BTM solar forecast, including the resulting demand and energy forecasts, are described in Appendix C.

### 4.3.4 Large Customer Growth Assumptions

The Company periodically reviews the growth plans of its largest customers in its service territory. These expected load increases can be uncertain and depend to a great extent on economic conditions. Table 4-1 shows anticipated large customer load additions and reductions (with confidence factor applied) for the RAP period 2022 through 2030. This information was compiled based on information gathered by the Company's economic development personnel and adjusted by a confidence factor depending on the level of certainty expressed by the customer that the growth will actually occur. These annual changes in large customer loads are reflected in the peak demand and energy load forecasts.

**Table 4-1**
**Large Customer Load Additions and Reductions 2022 - 2030**

| Customer | Load Factor | 2022 (MW) | 2023 (MW) | 2024 (MW) | 2025 (MW) | 2026 (MW) | 2027 (MW) | 2028 (MW) | 2029 (MW) | 2030 (MW) |
|---|---|---|---|---|---|---|---|---|---|---|
| Large Customer A | 87% | 1.0 | 0.0 | -5.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Large Customer B | 32% | 0.0 | 0.0 | 1.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Large Customer C | 50% | 1.5 | 0.5 | 0.3 | 0.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Large Customer D | 50% | 2.3 | 0.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Large Customer E | 45% | 2.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

## 4.4 Base Peak Demand and Annual Energy Forecasts

The final base system-level monthly peak demand forecast was computed by adding the one large customer and anticipated future load growth of other large customers into the load forecast calculated by the regression analysis. Effects of DSM and the net BTM solar demand forecast were also added into the load forecast.

The final system-level major customer class energy forecasts were computed by adding large customer loads, including their anticipated future load growth, lighting service, Company-use, effects of DSM, transmission and distribution losses, and the net BTM solar energy forecast to the energy forecasts calculated through the regression analysis.

Combined transmission and distribution losses were also added into the annual energy forecast for each major customer class. Losses were estimated by calculating a weighted loss percentage for each aggregated major class. The class level transmission and distribution losses are shown in Table 4-2. Separate system loss estimates cannot be made for transmission and distribution because the forecast was not developed at the transmission and distribution voltage level. The peak demand and energy forecast values for the base load forecast are shown in Table 4-3.

**Table 4-2**
**Combined Transmission and Distribution Losses**

| Major Sales Class | Line Loss Class | Average Estimated Losses | Aggregated Customer Class Weighted Losses by Class | Non-aggregated Customer Class Sales Losses |
|---|---|---|---|---|
| Residential | Residential | 5.506% | | 5.506% |
| Commercial | Large General Service - Primary | 3.765% | 5.352% | |
| | Large General Service - Secondary | 5.506% | | |
| | Small General Service | 5.506% | | |
| Industrial | Large Power Service - Primary | 3.765% | 3.820% | |
| | Large Power Service - Secondary | 5.506% | | |
| | Large Power Service - Transmission | 2.210% | | |
| Large Customer 1 | Large Customer 1 | 3.765% | | 3.765% |
| Large Customer 2 | Large Customer 2 | 3.765% | | 3.765% |
| Large Customer 3 | Large Customer 3 | 2.210% | | 2.210% |
| Lighting | | 5.506% | | 5.506% |
| Company Use | | 5.506% | | 5.506% |
| Auxiliary | Total System | | 3.100% | |
| | Station Use | | | |

**Table 4-3**
**Base Load Forecast**

| Year | Peak Demand* (MW) | Annual Energy* (MWh) | Losses (MWh) |
|---|---|---|---|
| 2022 | 435.5 | 2,111,958 | 151,869 |
| 2023 | 441.7 | 2,109,386 | 152,056 |
| 2024 | 442.6 | 2,063,331 | 150,945 |
| 2025 | 448.5 | 2,075,814 | 151,605 |
| 2026 | 449.7 | 2,085,018 | 152,180 |
| 2027 | 450.8 | 2,094,518 | 152,778 |
| 2028 | 451.9 | 2,103,554 | 153,338 |
| 2029 | 453.0 | 2,112,511 | 153,890 |
| 2030 | 454.0 | 2,122,155 | 154,497 |
| 2031 | 455.0 | 2,131,721 | 155,097 |
| 2032 | 456.0 | 2,140,816 | 155,659 |
| 2033 | 456.9 | 2,150,224 | 156,245 |
| 2034 | 457.9 | 2,159,963 | 156,857 |
| 2035 | 458.8 | 2,169,263 | 157,434 |
| 2036 | 459.7 | 2,178,527 | 158,007 |
| 2037 | 460.5 | 2,188,144 | 158,607 |
| 2038 | 461.4 | 2,197,711 | 159,203 |
| 2039 | 462.2 | 2,206,829 | 159,763 |
| 2040 | 463.0 | 2,215,912 | 160,321 |
| 2041 | 463.7 | 2,225,370 | 160,909 |
| 2042 | 464.5 | 2,234,422 | 161,466 |
| 2043 | 465.2 | 2,243,467 | 162,022 |
| 2044 | 465.9 | 2,252,894 | 162,610 |
| 2045 | 466.6 | 2,261,897 | 163,165 |
| 2046 | 467.3 | 2,270,482 | 163,687 |
| 2047 | 468.0 | 2,279,057 | 164,209 |
| 2048 | 468.6 | 2,287,636 | 164,732 |
| 2049 | 469.3 | 2,296,224 | 165,258 |
| 2050 | 469.9 | 2,304,816 | 165,785 |

*Peak Demand and Annual Energy Forecast values includes impacts of DSM Plans and losses.

## 4.5 Low and High Forecasts

The base load forecast is assumed to represent the expected midpoint of possible future outcomes, meaning that a future year's actual load may deviate from the midpoint projections. To evaluate the impact of these potential deviations, low, and high load forecasts were developed.

The Company prepared low and high load forecasts in addition to its base load forecast as required by Rule 3606(b). For the high and low load forecasts, the Company developed an 80 percent confidence interval band around the base demand and sales forecasts, using the economic estimator Gross Regional Product ("GRP").

The peak demand model provided an estimate of the effect of changes in GRP on changes in peak demand, along with a standard error associated with the estimate. These two uncertainties (in GRP over time and in the estimated effect of GRP on peak demand) are combined to produce the confidence interval around the demand and sales forecasts. The specific steps used to develop the confidence interval are described in Appendix B.

## 4.6 Increased Electrification Forecast

The Increased Electrification forecast was developed by E3 and added to the base load forecast for analysis in the Increased Electrification scenario. Table 4-4 below shows the increased electrification scenario and the detailed breakdown of different load components, including vehicle electrification and building electrification. The electrification loads were taken from projections developed for the state of Colorado in Colorado's Greenhouse Gas Pollution Reduction Roadmap and were downscaled based on the Company's share of statewide load in 2019. Building and transportation electrification are expected to drive significant load growth in Colorado Electric's system in the long term in this scenario. The system average annual growth rate is expected to be 2.1%. Total system load will reach 3,895 GWh by 2050, almost double of the current system load. Additional details for this forecast can be found in E3's Technical Report (Appendix F).

**Table 4-4**
**Increased Electrification Forecast**

| Units: GWh | 2022 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|
| Residential Space Heating | 5.5 | 27.4 | 90.7 | 168.0 | 258.2 | 335.8 | 378.3 |
| Commercial Space Heating | 2.2 | 10.4 | 33.6 | 63.6 | 93.6 | 112.3 | 119.9 |
| Residential Water Heating | 1.1 | 6.4 | 29.7 | 59.7 | 81.6 | 95.3 | 104.3 |
| Commercial Water Heating | 0.4 | 2.1 | 7.2 | 14.9 | 22.5 | 27.9 | 31.3 |
| LDV Charging | 8.9 | 40.9 | 137.9 | 269.3 | 402.4 | 506.4 | 575.9 |
| MHDV Charging | 3.6 | 16.7 | 55.2 | 129.3 | 232.8 | 317.8 | 380.5 |
| | | | | | | | |
| Total Building Electrification Load | 9.2 | 46.2 | 161.2 | 306.2 | 455.9 | 571.2 | 633.8 |
| Total Vehicle Electrification Load | 12.5 | 57.6 | 193.0 | 398.6 | 635.1 | 824.2 | 956.4 |

The values for the base, low and high load forecasts, including the effects of DSM are shown in Table 4-5.

**Table 4-5**
**Low, Base, and High Load Forecasts**

| Year | Peak Demand (MW) | | | Energy (GWh) | | |
|---|---|---|---|---|---|---|
| | Low | Base | High | Low | Base | High |
| 2022 | 433.2 | 435.5 | 437.7 | 2,105 | 2,112 | 2,119 |
| 2023 | 437.3 | 441.7 | 446.2 | 2,096 | 2,109 | 2,122 |
| 2024 | 435.9 | 442.6 | 449.3 | 2,044 | 2,063 | 2,083 |
| 2025 | 439.7 | 448.5 | 457.5 | 2,049 | 2,076 | 2,102 |
| 2026 | 438.7 | 449.7 | 460.9 | 2,052 | 2,085 | 2,119 |
| 2027 | 437.7 | 450.8 | 464.2 | 2,054 | 2,095 | 2,136 |
| 2028 | 436.8 | 451.9 | 467.6 | 2,056 | 2,104 | 2,153 |
| 2029 | 435.7 | 453.0 | 470.9 | 2,058 | 2,113 | 2,169 |
| 2030 | 434.7 | 454.0 | 474.1 | 2,060 | 2,122 | 2,186 |
| 2031 | 433.7 | 455.0 | 477.4 | 2,062 | 2,132 | 2,204 |
| 2032 | 432.7 | 456.0 | 480.6 | 2,064 | 2,141 | 2,220 |
| 2033 | 431.7 | 456.9 | 483.8 | 2,067 | 2,150 | 2,238 |
| 2034 | 430.6 | 457.9 | 487.0 | 2,069 | 2,160 | 2,256 |
| 2035 | 429.6 | 458.8 | 490.1 | 2,071 | 2,169 | 2,273 |
| 2036 | 428.5 | 459.7 | 493.3 | 2,073 | 2,179 | 2,290 |
| 2037 | 427.5 | 460.5 | 496.4 | 2,076 | 2,188 | 2,308 |
| 2038 | 426.4 | 461.4 | 499.5 | 2,078 | 2,198 | 2,326 |
| 2039 | 425.3 | 462.2 | 502.5 | 2,080 | 2,207 | 2,343 |
| 2040 | 424.3 | 463.0 | 505.5 | 2,083 | 2,216 | 2,360 |
| 2041 | 423.2 | 463.7 | 508.6 | 2,085 | 2,225 | 2,378 |
| 2042 | 422.1 | 464.5 | 511.6 | 2,087 | 2,234 | 2,395 |
| 2043 | 421.0 | 465.2 | 514.5 | 2,090 | 2,243 | 2,412 |
| 2044 | 419.9 | 465.9 | 517.5 | 2,092 | 2,253 | 2,430 |
| 2045 | 418.8 | 466.6 | 520.5 | 2,094 | 2,262 | 2,447 |
| 2046 | 417.7 | 467.3 | 523.4 | 2,097 | 2,270 | 2,464 |
| 2047 | 416.6 | 468.0 | 526.3 | 2,099 | 2,279 | 2,480 |
| 2048 | 415.4 | 468.6 | 529.3 | 2,101 | 2,288 | 2,496 |
| 2049 | 414.3 | 469.3 | 532.2 | 2,104 | 2,296 | 2,513 |
| 2050 | 413.1 | 469.9 | 535.1 | 2,106 | 2,305 | 2,529 |

Table 4-6 shows the total system summer and winter peak demand forecast for each year of the Planning Period.

**Table 4-6**
**Seasonal Peak Demand Load Forecast Comparison – Base, Low, and High**
**(including impacts of DSM Plans)**

| Year | Peak Summer Demand (MW) | | | Peak Winter Demand (MW) | | |
|---|---|---|---|---|---|---|
| | Low | Base | High | Low | Base | High |
| 2022 | 433.2 | 435.5 | 437.7 | 332.1 | 332.8 | 333.5 |
| 2023 | 437.3 | 441.7 | 446.2 | 334.4 | 335.8 | 337.1 |
| 2024 | 435.9 | 442.6 | 449.3 | 331.5 | 333.5 | 335.5 |
| 2025 | 439.7 | 448.5 | 457.5 | 335.6 | 338.2 | 340.9 |
| 2026 | 438.7 | 449.7 | 460.9 | 334.9 | 338.2 | 341.5 |
| 2027 | 437.7 | 450.8 | 464.2 | 334.2 | 338.1 | 342.1 |
| 2028 | 436.8 | 451.9 | 467.6 | 333.5 | 338.0 | 342.7 |
| 2029 | 435.7 | 453.0 | 470.9 | 332.8 | 338.0 | 343.2 |
| 2030 | 434.7 | 454.0 | 474.1 | 332.1 | 337.9 | 343.8 |
| 2031 | 433.7 | 455.0 | 477.4 | 331.4 | 337.7 | 344.3 |
| 2032 | 432.7 | 456.0 | 480.6 | 330.6 | 337.6 | 344.8 |
| 2033 | 431.7 | 456.9 | 483.8 | 329.9 | 337.5 | 345.3 |
| 2034 | 430.6 | 457.9 | 487.0 | 329.2 | 337.4 | 345.8 |
| 2035 | 429.6 | 458.8 | 490.1 | 328.5 | 337.2 | 346.2 |
| 2036 | 428.5 | 459.7 | 493.3 | 327.8 | 337.1 | 346.7 |
| 2037 | 427.5 | 460.5 | 496.4 | 327.0 | 336.9 | 347.1 |
| 2038 | 426.4 | 461.4 | 499.5 | 326.3 | 336.7 | 347.5 |
| 2039 | 425.3 | 462.2 | 502.5 | 325.6 | 336.6 | 347.9 |
| 2040 | 424.3 | 463.0 | 505.5 | 324.9 | 336.4 | 348.4 |
| 2041 | 423.2 | 463.7 | 508.6 | 324.1 | 336.2 | 348.7 |
| 2042 | 422.1 | 464.5 | 511.6 | 323.4 | 336.0 | 349.1 |
| 2043 | 421.0 | 465.2 | 514.5 | 322.7 | 335.8 | 349.5 |
| 2044 | 419.9 | 465.9 | 517.5 | 321.9 | 335.6 | 349.8 |
| 2045 | 418.8 | 466.6 | 520.5 | 321.2 | 335.3 | 350.2 |
| 2046 | 417.7 | 467.3 | 523.4 | 320.4 | 335.1 | 350.5 |
| 2047 | 416.6 | 468.0 | 526.3 | 319.7 | 334.9 | 350.9 |
| 2048 | 415.4 | 468.6 | 529.3 | 318.9 | 334.6 | 351.2 |
| 2049 | 414.3 | 469.3 | 532.2 | 318.2 | 334.4 | 351.5 |
| 2050 | 413.1 | 469.9 | 535.1 | 317.4 | 334.2 | 351.9 |

## 4.7 Historical Peak Demand and Annual Energy and Comparison to the 2016 ERP

The Company has historically experienced its annual peaks in the summer. Peak demand and annual energy for the period 2017-2021 are provided on Table 4-7. Since 2017, the summer peak has experienced an average annual growth rate of 0.62 percent, the winter peak has experienced an average annual declining growth rate of -0.24 percent, and the historical annual energy experienced an average annual declining growth rate of -0.04 percent.

**Table 4-7**
**Historical Peak Demand and Annual Energy**

| | Peak Demand | | | | Annual Energy* | | Summer Load Factor (%) | Winter Load Factor (%) |
|---|---|---|---|---|---|---|---|---|
| Year | Summer (MW) | Summer % Change | Winter (MW) | Winter % Change | GWh | % Change | | |
| 2017 | 398 | | 299 | | 2,055 | | 58.95% | 78.47% |
| 2018 | 413 | 3.77% | 291 | -2.68% | 2,125 | 3.37% | 58.73% | 83.35% |
| 2019 | 422 | 2.18% | 292 | 0.34% | 2,104 | -0.97% | 56.92% | 82.26% |
| 2020 | 401 | -4.98% | 297 | 1.71% | 2,052 | -2.46% | 58.42% | 78.88% |
| 2021 | 407 | 1.50% | 296 | -0.34% | 2,051 | -0.08% | 57.52% | 79.08% |
| Average Annual Growth (%) | | 0.62% | | -0.24% | | -0.04 | | |
| * Annual energy includes transmission and distribution losses. | | | | | | | | |

A comparison of the peak demand and energy forecasts from the 2016 ERP and this 2022 ERP is shown in Table 4-8. In the 2016 ERP, the annual energy growth was projected at 0.82 percent over the 2016-2040 period, as compared to the 0.31 percent growth rate projection in the current plan over the 2022-2050 time period. The annual peak demand growth over the 2016-2040 period was forecasted at 0.44 percent in the 2016 ERP, compared to the peak demand 2022 ERP growth rate projected to be 0.27 percent, as shown in Table 4-8.

**Table 4-8**
**Peak Demand and Energy Forecast Comparison**

| Year | Annual Energy (GWh) | | Peak Demand DSM (MW) | |
|---|---|---|---|---|
| | 2016 ERP | 2022 ERP | 2016 ERP | 2022 ERP |
| 2016 | 2,037 | | 395 | |
| 2017 | 2,066 | | 395 | |
| 2018 | 2,085 | | 394 | |
| 2019 | 2,124 | | 397 | |
| 2020 | 2,156 | | 401 | |
| 2021 | 2,157 | | 401 | |
| 2022 | 2,145 | 2,112 | 397 | 435 |
| 2023 | 2,152 | 2,109 | 398 | 442 |
| 2024 | 2,174 | 2,063 | 401 | 443 |
| 2025 | 2,195 | 2,076 | 404 | 449 |
| 2026 | 2,216 | 2,085 | 406 | 450 |
| 2027 | 2,237 | 2,095 | 409 | 451 |
| 2028 | 2,259 | 2,104 | 411 | 452 |
| 2029 | 2,280 | 2,113 | 414 | 453 |
| 2030 | 2,301 | 2,122 | 416 | 454 |
| 2031 | 2,320 | 2,132 | 419 | 455 |
| 2032 | 2,338 | 2,141 | 421 | 456 |
| 2033 | 2,356 | 2,150 | 423 | 457 |
| 2034 | 2,375 | 2,160 | 426 | 458 |
| 2035 | 2,393 | 2,169 | 428 | 459 |
| 2036 | 2,411 | 2,179 | 430 | 460 |
| 2037 | 2,428 | 2,188 | 432 | 461 |
| 2038 | 2,444 | 2,198 | 435 | 461 |
| 2039 | 2,460 | 2,207 | 437 | 462 |
| 2040 | 2,477 | 2,216 | 439 | 463 |
| 2041 | | 2,225 | | 464 |
| 2042 | | 2,234 | | 464 |
| 2043 | | 2,243 | | 465 |
| 2044 | | 2,253 | | 466 |
| 2045 | | 2,262 | | 467 |
| 2046 | | 2,270 | | 467 |
| 2047 | | 2,279 | | 468 |
| 2048 | | 2,288 | | 469 |
| 2049 | | 2,296 | | 469 |
| 2050 | | 2,305 | | 470 |
| **2016 - 2040** | **0.82%** | | **0.44%** | |
| **2022 – 2050** | | **0.31%** | | **0.27%** |

## 4.8 Energy and Capacity Sales to Other Utilities and Intra-Utility Energy and Capacity Sales and Losses

Pursuant to Rule 3606(a)(III), the Company must provide a forecast of annual energy and capacity sales to other utilities, in addition to capacity sales to other utilities at the time of coincident summer and winter peak demand. The Company does not have any energy or capacity contracts with other utilities and therefore has no data to provide.

Pursuant to Rule 3606(a)(IV), the Company must provide a forecast of annual intra-utility energy and capacity use at the time of coincident summer and winter peak demand. The Company does not have any intra-utility energy or capacity contracts and therefore has no data to provide.

## 4.9 Load Profiles

Typical day load patterns for Colorado Electric's system load presented for peak day, average day, and representative average off-peak days for each calendar month are provided in Appendix D. These monthly load shapes were developed from hourly system demand data for the year 2020 and reflect average customer use for the system.

# Black Hills Colorado Electric Generator Interconnection Queue

Black Hills' Large Generator Interconnection Queue is available at the following link: LGI Queue

Black Hills' Cluster 1 Interconnection Queue is available at the following link: Cluster 1 Queue

# Black Hills Energy Facility Rating Methodology

| DOCUMENT TITLE: **BHC Facility Rating Methodology** | EFFECTIVE DATE: **31-Dec-2012** | DOCUMENT NO. **TP-P-002** |
|---|---|---|
| DOCUMENT OWNER: **Trevor Rombough, Manager of Transmission Planning** | REVISED DATE: **12-Sep-2024** | REV.VER: **3.1** |
| | | Page 1 of 18 |
| | | CONFIDENTIALITY CATEGORY: **Public** |

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# 1 Purpose

This document contains the philosophies and methodology used for determining and communicating Facility Ratings for solely and jointly owned transmission and generation Facilities of Black Hills Corporation's (BHC) subsidiaries: Black Hills/Colorado Electric (BHCE), Black Hills Power (BHP), Black Hills Wyoming (BHW), Black Hills Colorado IPP (BHCI) and Cheyenne Light, Fuel and Power (CLFP). The document also defines the basis for the calculation of Normal and Emergency Ratings of BHC Facilities at 100 kV and above to satisfy the requirements of NERC Reliability Standard FAC-008-5. For the remainder of this document the term BHC shall be read to include BHCE, BHP, BHW, BHCI and CLFP except as otherwise noted.

## *1.1 Statement on Facility Rating limits (FAC-008-5 R2.3 and R3.3)*

The Facility Rating for transmission and generation facilities shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. For jointly owned transmission and generation facilities, BHC will coordinate its equipment ratings with the other facility owner's equipment ratings to determine the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

## *1.2 Method to Determine Most Limiting Facility*

BHC has developed a rating methodology for each major component of equipment that comprises a Facility. All series equipment that together make up a line section, transmission substation transformer circuit, or shunt reactive device are reviewed to determine which item of equipment has the most limiting rating, which will be used as the most limiting component in determining the normal and emergency ratings for the transmission facility.

All series equipment that together make up the generating facility from the generator to, and possibly including, the generator step-up transformer are reviewed to determine which item of equipment has the most limiting rating, will be used as the most limiting component in determining the normal and emergency ratings for the generating facility. Generator Owner equipment connected between the point of interconnection up to, and possibly including, the generator step-up transformer will have Facility Ratings determined per the Transmission Facility Rating Methodology in Section 5 below.

# 2 Definitions

## *2.1 Terms defined in the "Glossary of Terms Used in NERC Reliability Standards"*

2.1.1 This document defines the following terms typically per the revision of the "Glossary of Terms Used in NERC Reliability Standards" dated December 2, 2022:

2.1.2 **Element:** Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.

2.1.3 **Equipment Rating:** The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.

2.1.4 **Facility:** A set of electrical equipment that operates as a single BES Element (e.g., a line, a generator, a shunt compensator, transformer, etc.). Appendix B contains more details on what equipment is considered for each facility.

2.1.5 **Facility Rating:** The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable Equipment Rating of any equipment comprising the Facility.

2.1.6 **Emergency Rating:** The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in Amps, MVA or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

2.1.7 **Normal Rating:** The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in Amps, MVA or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

2.1.8 **Reasonability Limit**: The value representing the maximum measurement capability of an element, determined by the maximum reading of terminal equipment instrumentation and widest range of SCADA/EMS measurement capabilities.

2.1.9 **Summer:** The time period associated with seasonal ratings extending from April 1 thru November 30.

2.1.10 **Winter:** The time period associated with seasonal ratings extending from December 1 thru March 31.

# 3 Scope

3.1.1 This procedure is to ensure the Facility Ratings, used in the reliable planning and operations of the BHC Facilities are determined based on an established methodology.

3.1.2 This document describes BHC's ratings methodology and compliance with NERC reliability standard FAC-008-5. The appendices to this document assign ratings responsibilities, outlines the Facility Ratings process and records associated with establishing, updating, issuing, and disseminating accurate and appropriate ampacity ratings for BHC Facilities

3.1.3 This document is applicable to all personnel engaged in planning, engineering, maintenance, construction and operation of BHCs Facilities.

# 4 Generation Facility Rating Methodology

## *4.1 General*

All BHC solely or jointly owned generator Facilities are described as consisting of the generator and all applicable equipment from the generator to the point of interconnection with the Transmission Owner. The generation facilities generally consist of the generator, the generator step-up transformer (GSU), and the associated equipment between the generator and the GSU.

## *4.2 Generators*

BHC rates generators based on the manufacturer's nameplate. The generators are not operated above the nameplate rating. Therefore, Emergency Ratings are considered the same as the Normal Ratings. Operating limitations may be included if applicable.

## *4.3 GSU Transformers*

The GSU transformers will be rated according to the methods described in Section 5.1.

## *4.4 Generation Facility Electric Equipment*

The electric equipment connecting the generator and the GSU transformer will be rated per documented manufacturer's design criteria, equipment nameplate ratings, engineering analyses, and industry standards. All assumptions utilized in determining generator Facility Ratings shall be clearly identified within the supporting documentation. Further details on the rating methodology for generation facility equipment are included in Section 5.

Each generation Facility Rating must take into account any known limitations based on operating conditions, etc. according to good utility practice.

# 5 Transmission Facility Rating Methodology

The transmission facilities owned by BHC's transmission-owner ("TO") subsidiaries as well as those owned by the generator-owner ("GO") subsidiaries will be similarly rated according to this methodology as described in Sections 5.1 through 5.11

## *5.1 Transformers*

All transformers with low-side windings connected at 69 kV nominal or above have been rated in accordance with the manufacturer's specifications as well as IEEE Standard C57.91-(*latest version*).

5.1.1 The Normal Rating for power transformers is 100% of the manufacturer's highest continuous nameplate (AN, AF, ON, OF, or OD) rating. When available, the normal rating will use the 65 $^{o}$C temp rise nameplate rating. The 55 $^{o}$C temp rise rating will only be used if a 65 $^{o}$C temp rise rating is not listed.

5.1.2 The Emergency Rating for power transformers is based on the manufacturers stated nameplate Emergency Rating, however if the manufacturer does not specify an Emergency Rating then BHC will assume 125% of the Normal Rating for a maximum of 30 minutes.

BHC may allow for a Normal and/or Emergency Rating beyond the stated value which will be determined on a per Facility basis and through an engineering analysis of that Facility consistent with the IEEE/ANSI standards listed above or other appropriately established criteria. Power transformers may also be subject to ambient conditions that may result in the adjustment of the manufacturers rating due to real-time conditions such as temperature. Operating limitations may also be placed on the power transformers such as de-rating due to impaired equipment which follows good utility practice.

## *5.2 Bare Overhead Flexible Conductors*

The rating of a transmission conductor is the amount of current, measured in amperes (amps), which can be safely carried over the line. BHC's transmission line ratings are based on IEEE Standard 738-2012 for calculating the current-temperature relationship of bare overhead conductors and are calculated using commercially available computer software unless otherwise specified. BHC calculates Normal and 2-Hour Emergency ratings on transmission conductors based on the maximum conductor temperatures for the conductor types included in **Table 5-1**. Normal and Emergency conductor ratings for conductor types not included in **Table 5-1** are determined on a per Facility basis through an Engineering analysis. Input variables required for the Normal and Emergency ratings calculations include physical conductor properties obtained from the appropriate conductor reference. BHC may allow for a Normal and/or Emergency Rating beyond the stated value which will be determined on a per Facility basis and through an Engineering analysis of that Facility consistent with the IEEE/ANSI Standards listed above or other appropriately established criteria.

Variables needed to establish conductor ratings which **ARE NOT** location dependent are included in **Table 5-2**. Other conductor variables needed to establish conductor ratings which **ARE** location dependent are included in **Table 5-3**. All other input variables not identified in **Table 5-2** and **Table 5-3** are based upon the design of the specific transmission facility.

**Table 5-1: Maximum Conductor Temperatures**

| Conductor Type | Normal Ratings Conductor Temperature (°C) | 2-Hour Emergency Ratings Conductor Temperature (°C) |
|---|---|---|
| **ACCC** | 180 | 200 |
| **ACSR** | 95 | 100 |
| **AAC** | 95 | 100 |

**Table 5-2: Environment Variable Assumptions**

| Parameter | Value |
|---|---|
| **Ambient air temperature (Summer) (°C/°F)** | 40 / 104 |
| **Ambient air temperature (Winter) (°C/°F)** | 10 / 50 |
| **Transmission Line Wind Speed (mps/fps)** | 1.22 / 4.0 |
| **Substation Conductor Wind Speed (mps/fps)** | 0.6 / 2.0 |
| **Wind Direction** | Perpendicular to conductor axis (90°) |
| **Line Orientation** | East-West (90° or 270°) |
| **Summer Reference Date** | June 10 |
| **Winter Reference Date** | December 10 |
| **Time of Day** | 12:00 pm |
| **Atmosphere** | Clear |
| **Absorptivity** | 0.5 |
| **Emissivity** | 0.5 |

**Table 5-3: Location Variable Assumptions**

| Parameter | BHCE | BHP | CLFP |
|---|---|---|---|
| **Latitude (°N)** | 38.00 | 44.00 | 41.00 |
| **Elevation (ft)** | 4700 | 3100 | 6100 |

#### 5.2.1 Flexible Substation Conductors

Substation conductors, such as strain bus and equipment jumpers within the substation will utilize the conductor assumptions identified in **Table 5-2** and **Table 5-3**. Additionally, substation conductors will utilize the substation conductor wind speed found in **Table 5-2**. Substation conductor ratings are calculated using commercially available computer software unless otherwise specified.

#### 5.2.2 Transmission Line Conductors

Transmission line conductors will utilize the environment and location assumptions identified in **Table 5-2** and **Table 5-3**, and the maximum conductor temperature in **Table 5-1** or as determined by specific Engineering Analysis based upon the transmission line design and/or minimum safety clearances. Unless otherwise specified in the equipment rating documentation, transmission line jumpers between a transmission line and substation equipment will utilize the transmission line assumptions identified in **Table 5-1, Table 5-2,** and **Table 5-3**. Commercially available computer software is used in the calculation of line jumper ratings unless otherwise specified.

## *5.3 Rigid Bus Conductors*

The rigid bus conductor ratings are determined per IEEE Standard 605-2008. Normal and 2-Hour Emergency Ratings for rigid bus conductors used in outdoor substations are based on the ampacity tables within IEEE Standard 605-2008 Annex B for the appropriate bus type with the assumptions noted in **Table 5-4**: . Operating limitations may also be placed on the rigid bus conductors such as a de-rate due to impaired equipment.

**Table 5-4: Rigid Bus Variable Assumptions**

| Parameter | Normal Ratings Value | 2-Hour Emergency Ratings Value |
|---|---|---|
| **Ambient Temperature** | 40°C | 40°C |
| **Latitude** | 40°N | 40°N |
| **Bus Direction** | East-West | East-West |
| **Wind Speed (fps/mps)** | 2.0 / 0.6 | 2.0 / 0.6 |
| **Wind Direction** | Perpendicular to conductor axis | Perpendicular to conductor axis |
| **Solar Absorptivity** | 0.5 | 0.5 |
| **Emissivity (with sun)** | 0.5 | 0.5 |
| **Temp Rise (above 40°C ambient)** | 40°C | 50°C |

## 5.4 Circuit Breakers

High-voltage circuit breakers are specified by operating voltage, continuous current, interrupting current and operating time in accordance with IEEE Standards C37 series. These ratings are indicated on the individual circuit breaker nameplate. BHC rates transmission circuit breakers according to the manufacturer's specifications.

The normal rating for BHC transmission circuit breakers are rated as shown on the manufacturer's nameplate. Nameplate interrupting ratings are adjusted for reclosing of oil circuit breakers per IEEE Standard C37.04. BHC does not have ratings above normal for transmission circuit breakers therefore no emergency ratings are provided as they would be equal to the normal ratings.

## 5.5 Instrument Transformers

Free standing current transformers, metering units or voltage transformers, are specified in accordance with IEEE Standard C57.13.

BHC rates transmission instrument transformers according to the manufacturer's specifications. The Normal Ratings for BHC transmission instrument transformers are rated as shown on the manufacturer's nameplate. BHC accounts for the tapped ratio and the thermal rating factor when rating current transformers. BHC allows for ratings above normal for transmission instrument transformers as allowed per the manufacturer.

### 5.5.1 Reasonability Limits of Instrument Transformers

To account for real-time adjusted ambient air temperatures and ensure the reliability of BHC's transmission system equipment, reasonability limits are set by the maximum reading that can be measured by an instrument transformer and read into the SCADA/EMS. Transmission lines may be capable of delivering a higher rating of current than the reasonability limit, which may lead to the use of software modeling and simulations to ensure system operating limits are not exceeded. The maximum reading of the instrument transformers is included and noted as a limiting element within BHC's rating analysis to ensure that BHC is using appropriate real-time values for the full range of element capacity; however, instrument transformer limitations are not included in the calculation of Normal and Emergency ratings.

## 5.6 Switches

Transmission switches are specified in accordance with IEEE Standard C37.37.

BHC rates transmission switches according to the manufacturer's specifications. The Normal Ratings for BHC switches are rated as shown on the manufacturer's nameplate. Emergency ratings shall be equal to normal ratings.

## 5.7 Protective Equipment

PRC-023-4 states that each TO and GO shall use the standard criteria to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. The facility rating may be limited by protective relay settings for low risk scenarios where facility overloads are unlikely. For these situations, the PRC-023-4 criteria will be used to determine a reasonable facility rating based on the existing protection settings.

## 5.8 Line Traps

Line traps are specified in accordance with ANSI Standard C93.3.

BHC will utilize the manufacturer's continuous nameplate rating for both Normal and Emergency Ratings for all seasons except for air-core inductor type line traps. Air-core inductor type line traps will be allowed to have a 2-hour Emergency Rating equal to 110% of the Normal Rating within the limits allowed by ANSI Standard C93.3. This Emergency Rating will not be utilized in planning assessments, but will be available in the operating time frame.

## 5.9 Series Compensation Devices

BHC rates transmission series compensation devices according to the manufacturer's specifications. The Normal Rating for transmission series compensation devices are rated as shown on the manufacturer's nameplate. Emergency ratings shall be equal to normal ratings.

## 5.10 Shunt Capacitors

Transmission shunt capacitors are specified in accordance with IEEE Standard C57.21.

BHC rates transmission shunt capacitors according to the manufacturer's specifications. The Normal Ratings for BHC shunt capacitors are rated as shown on the manufacturer's nameplate. Emergency ratings shall be equal to normal ratings.

## 5.11 Shunt Reactors

Transmission shunt reactors are specified in accordance with IEEE Standard 18, IEEE Standard 1036 and IEEE Standard C37.99.

BHC rates transmission shunt reactors according to the manufacturer's specifications. The Normal Ratings for BHC shunt reactors are rated as shown on the manufacturer's nameplate. Emergency ratings shall be equal to normal ratings.

# 6 Roles and Responsibilities

The specific roles and responsibilities of the individual groups within BHC as they pertain to BHC Facility Ratings include but are not limited to the items described below. Each BHC group listed below is responsible for their portion of the data provided and work performed as listed.

## 6.1 Transmission Planning

6.1.1 Maintain system planning models and associated change files (PSS/E format).

6.1.2 Communicate changes in system planning models to Operations Support.

6.1.3 Maintain the BHC Facility Ratings Methodology (TP-P-002).

6.1.4 Identify existing and future transmission system capacity needs.

6.1.5 Request desired normal and emergency ratings on planned facilities, and changes to existing facilities to Substation & Protection Engineering, and Transmission & Distribution Engineering.

6.1.6 Determine Facility Ratings based on most-limiting element comprising a facility.

6.1.7 Communicate established ratings to Substation & Protection Engineering, Transmission & Distribution Engineering, Operations Support, Reliability Center Operations, Electrical Maintenance, external utilities, and the Reliability Coordinator.

6.1.8 Maintain the Facility Ratings Update process.

6.1.9 Assume NERC Standard FAC-008-5 compliance reporting responsibilities.

6.1.10 Coordinate requests for information related to the BHC Facility Ratings Methodology (TP-P-002) with the appropriate BHC group and provide a response to the requesting entity within the required time frame.

6.1.11 Maintain element rating database (PTP spreadsheets)

## *6.2 Transmission & Distribution Engineering*

6.2.1 Develop and maintain documentation of the assumptions, methods, and design criteria used in the determination of ratings for transmission facility equipment in accordance with FAC-008-5.

6.2.2 Determine ratings of system equipment in accordance with the BHC Facility Rating Methodology (TP-P-002).

6.2.3 Design new transmission line projects to meet desired capacity specified by Transmission Planning.

6.2.4 Design modifications to existing transmission lines to meet desired capacity specified by Transmission Planning.

6.2.5 Communicate with Transmission Planning any disparities between the requested capacity and actual achievable capacity of a new transmission line.

6.2.6 Address requests for conductor rating exceptions or deviations from standard practice.

## *6.3 Substation & Protection Engineering*

6.3.1 Develop and maintain documentation of the assumptions, methods, and design criteria used in the determination of ratings for substation facility equipment in accordance with FAC-008-5.

6.3.2 Determine ratings of system equipment in accordance with the BHC Facility Rating Methodology (TP-P-002).

6.3.3 Design new projects to meet desired capacity specified by Transmission Planning.

6.3.4 Communicate with Transmission Planning any disparities between the requested capacity and actual achievable capacity of a new substation project.

6.3.5 Develop and maintain ratings one-line drawings for the documentation of new and existing terminal equipment ratings.

6.3.6 Coordinate with Electrical Maintenance on determining relay/metering limitations and CT ratios.

6.3.7 Coordinate and implement protection system setting changes associated with a change in facility ratings.

6.3.8 Address requests for equipment rating exceptions or deviations from standard practice.

## *6.4 Electrical Maintenance*

6.4.1 Coordinate scheduled equipment changes with Reliability Center Operations.

6.4.2 Install equipment per design.

6.4.3 Increase relay/CT settings as requested to meet desired equipment ratings.

6.4.4 Replace or modify terminal equipment to meet desired equipment ratings.

6.4.5 Add or modify transmission structures to meet desired ratings.

6.4.6 Perform updates on the maintenance data repository as applicable.

## *6.5 Reliability Center / Operational Support*

6.5.1 Observe and utilize proper facility ratings.

6.5.2 Update loading alarms and SCADA displays based on established facility ratings.

6.5.3 Notify Transmission Planning of real-time loading issues to be corrected.

6.5.4 Provide Transmission Planning with final approval for rating change requests.

6.5.5 Update BHC and external real-time models as necessary.

## *6.6 Power Delivery*

6.6.1 Develop and maintain documentation of the assumptions, methods, and design criteria used in the determination of ratings for generators and generation facility equipment in accordance with FAC-008-5.

6.6.2 Maintain Generation Element Rating database of equipment ratings.

6.6.3 Provide generation facility equipment ratings to Transmission Planning, Reliability Center / Operational Support, and Substation & Protection Engineering.

6.6.4 Coordinate requested rating changes to generation facilities with Reliability Center / Operational Support, Transmission Planning, Electrical Maintenance, Transmission & Distribution Engineering, and Substation & Protection Engineering.

# 7 Facility Rating Process

The process for updating the BHC Transmission Facility Ratings is described in Appendix B.

# 8 Points of Contact

The appropriate contacts for each of the BHC groups identified in **Section 6** are shown in Error! Reference source not found..

# 9 Revision History

| Rev. | Revision Date | Description | Revised By |
|---|---|---|---|
| 1.0 | 5/14/07 | BHP Facility Rating Methodology: New Document | EME |
| 1.1 | 6/30/08 | BHP Facility Rating Methodology: Updated generator and transmission line sections. | EME |
| 1.0 | 7/14/09 | BHCE Facility Rating Methodology: Converted to BHCE document from Aquila and changed conductor rating assumptions | EME |
| 1.1 | 7/22/09 | BHCE Facility Rating Methodology: Added “Relay Protective Devices” to “Terminal Equipment” section heading. | EME |
| 1.2 | 6/29/12 | BHCE Facility Rating Methodology: Added 30-min limit to Emergency Transformer Ratings of 125%. Added timeframes for overhead conductor seasonal ratings. | WRW |
| 2.0 | 12/31/12 | Combined BHP and BHCE Facility Rating Methodology documents into a single BHC document addressing the requirements of FAC-008-3. | WRW |
| 2.1 | 1/9/13 | Added Roles and Responsibilities section, Facility Rating Process in Appendix A, and Contacts section. Grammatical changes. | WRW, JK |
| 2.2 | 7/30/13 | Modified Flexible Substation Conductor description and included verbiage on equipment rated per manufacturer’s specifications on nameplates. | WRW, JK |
| 2.3 | 11/27/13 | Changed winter ambient temperature assumption to 10 °C. Combined duplicate sections for transmission facilities owned by the TO and GO. | WRW |
| 2.4 | 12/29/14 | Updated Section 5.1. | WRW |
| 2.5 | 6/8/15 | Added SME Review table, updated NERC Glossary reference, updated Section 5 assumptions and layout. Updated Section 4 content. Reworded Section 6.4.6. | WRW |
| 2.6 | 6/1/18 | Updated BHC contacts and subject matter experts. Added Summer and Winter reference dates to Table 5-1. Added comment in Section 5.2.1 that substation conductors assume 40°C ambient air temp year round. | WRW |
| 2.7 | 11/18/2020 | Updated generator ratings description. Updated section 5.2.1. to help clarify wind speed assumptions for different jumpers. Also, added sentence in 5.1.1 clarifying assumptions for transformer temp rise. Also, added Appendix A with facility details. | TR |
| 3.0 | 2/9/2023 | Addition of conductor temperature use in normal and emergency ratings in section 5.2 Bare Overhead Flexible Conductors. Addition of new table in section 5.2 and updated references to other tables.<br>Addition of emergency ratings to section 5.3 Rigid Bus Conductors.<br>Addition of section 5.5.1 Reasonability Limits of Instrumentation Transformers.<br>Minor text updates from previous audit discussions. | MR |
| 3.1 | 9/12/2024 | Updated document owner. Replacing signature table with email approvals. | TR |

# Appendix A

# Facility Details

**Summary:** Transmission facilities include the transmission line conductor and the relevant terminal equipment as specified for each bus arrangement in the figures below. The relevant terminal equipment is highlighted in yellow for each example.

Figure 1A below demonstrates which terminal equipment will be considered for a transmission line facility that terminates at a breaker and half substation. Everything in the highlighted bubble would be considered for the facility rating of Line 1.

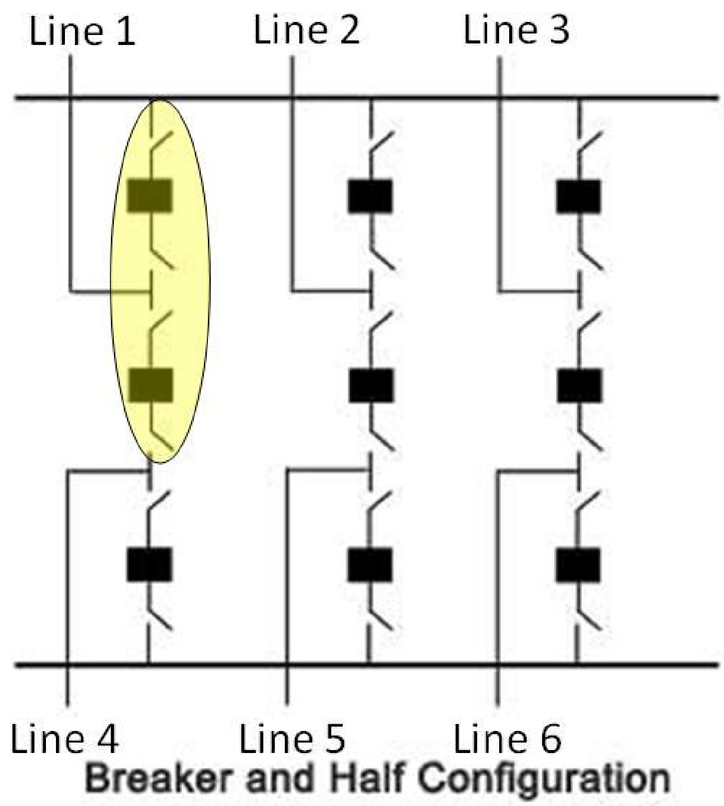



Figure 1A: Breaker and Half Terminal Equipment Considerations

Figure 2A below demonstrates which terminal equipment will be considered for a transmission line facility that terminates at a double bus double breaker substation. Everything in the highlighted bubble would be considered for the facility rating of Line 1.

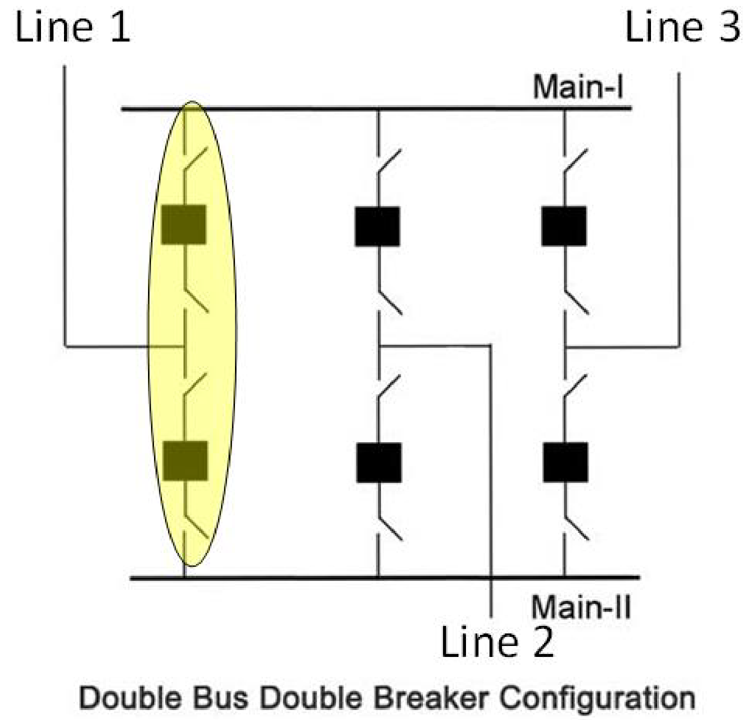



Figure 2A: Double Bus Double Breaker Terminal Equipment Considerations

Figure 3A below demonstrates which terminal equipment will be considered for a transmission line facility that terminates at a double bus single breaker substation. Everything in the highlighted bubble would be considered for the facility rating of Line 1.

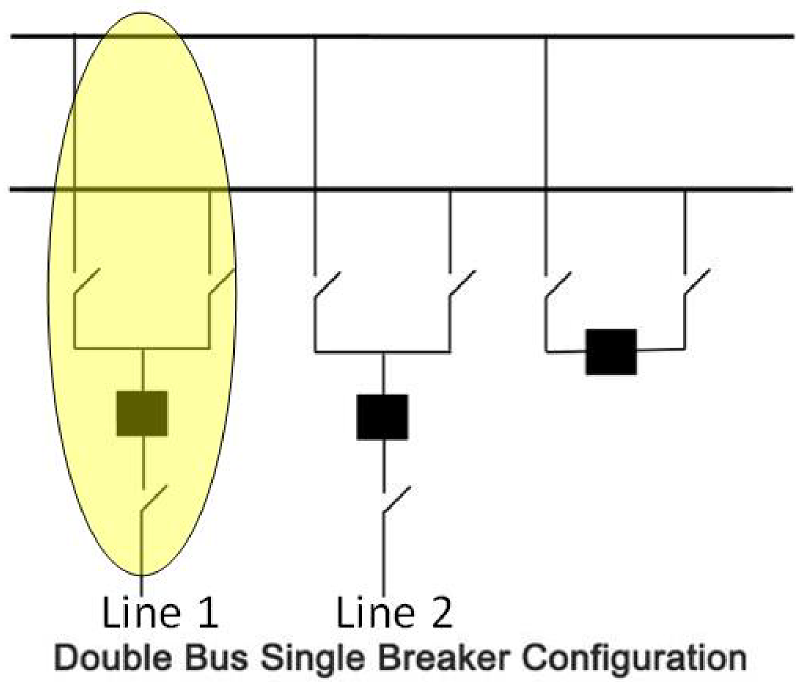



Figure 3A: Double Bus Single Breaker Terminal Equipment Considerations

Figure 4A below demonstrates which terminal equipment will be considered for a transmission line facility that terminates at a main and transfer substation. Everything in the highlighted bubble would be considered for the facility rating of Line 1.

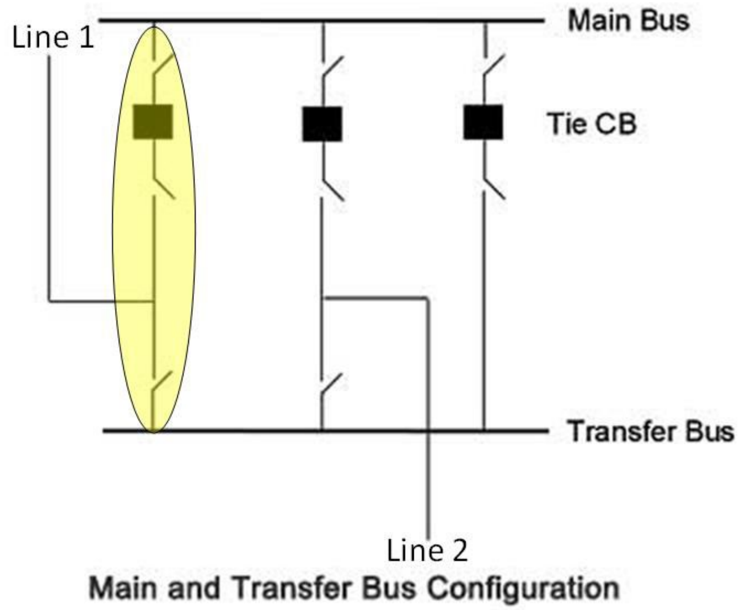



Figure 4A: Main and Transfer Bus Terminal Equipment Considerations

Figure 5A below demonstrates which terminal equipment will be considered for a transmission line facility that terminates at a ring bus substation. Everything in the highlighted bubble would be considered for the facility rating of Line 1.

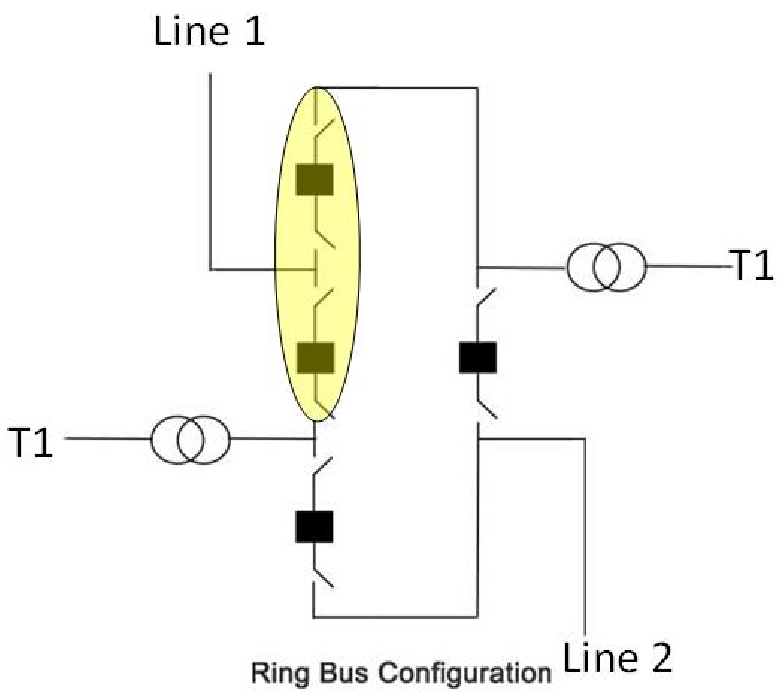



Figure 5A: Ring Bus Terminal Equipment Considerations

Figure 6A below demonstrates which terminal equipment will be considered for a transmission line facility that terminates at a single bus substation. Everything in the highlighted bubble would be considered for the facility rating of Line 2.

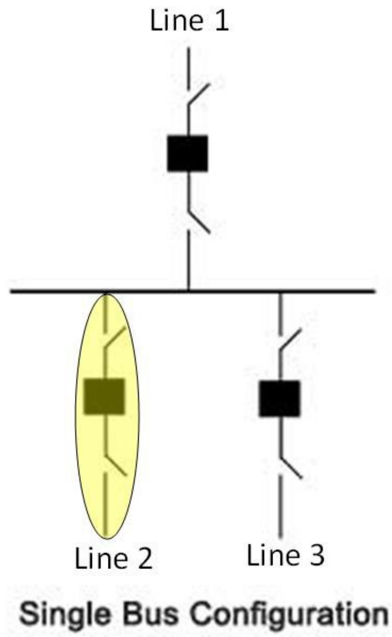


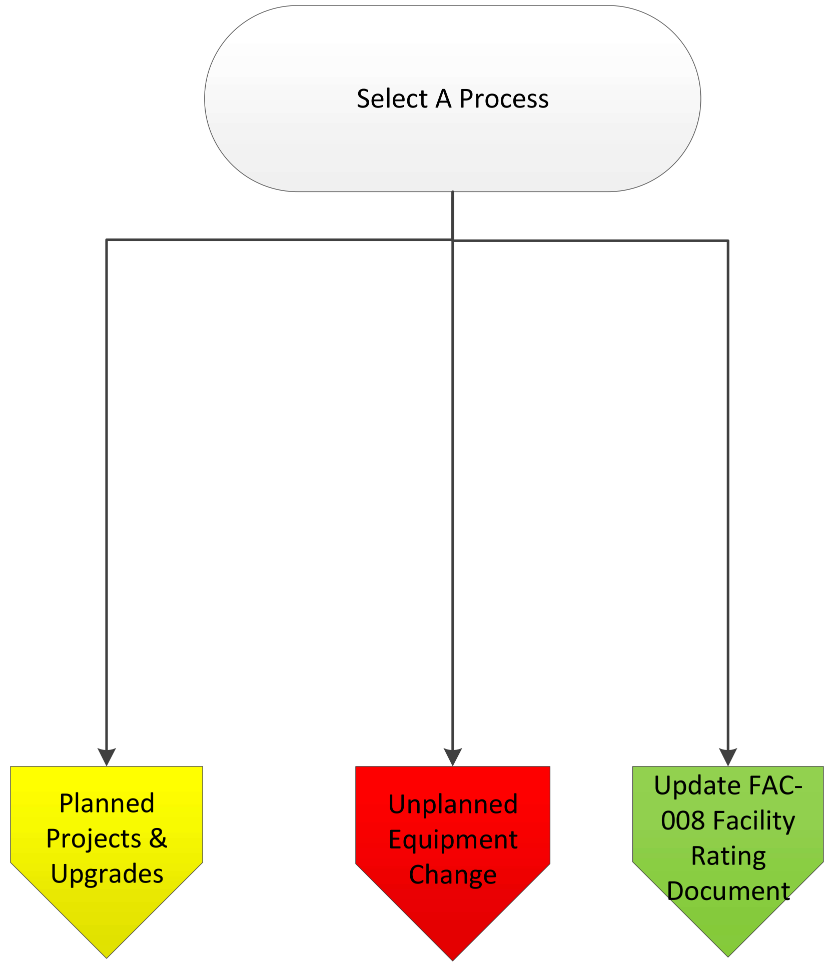

Figure 6A: Single Bus Terminal Equipment Consideration

# Appendix B

# Facility Rating Process

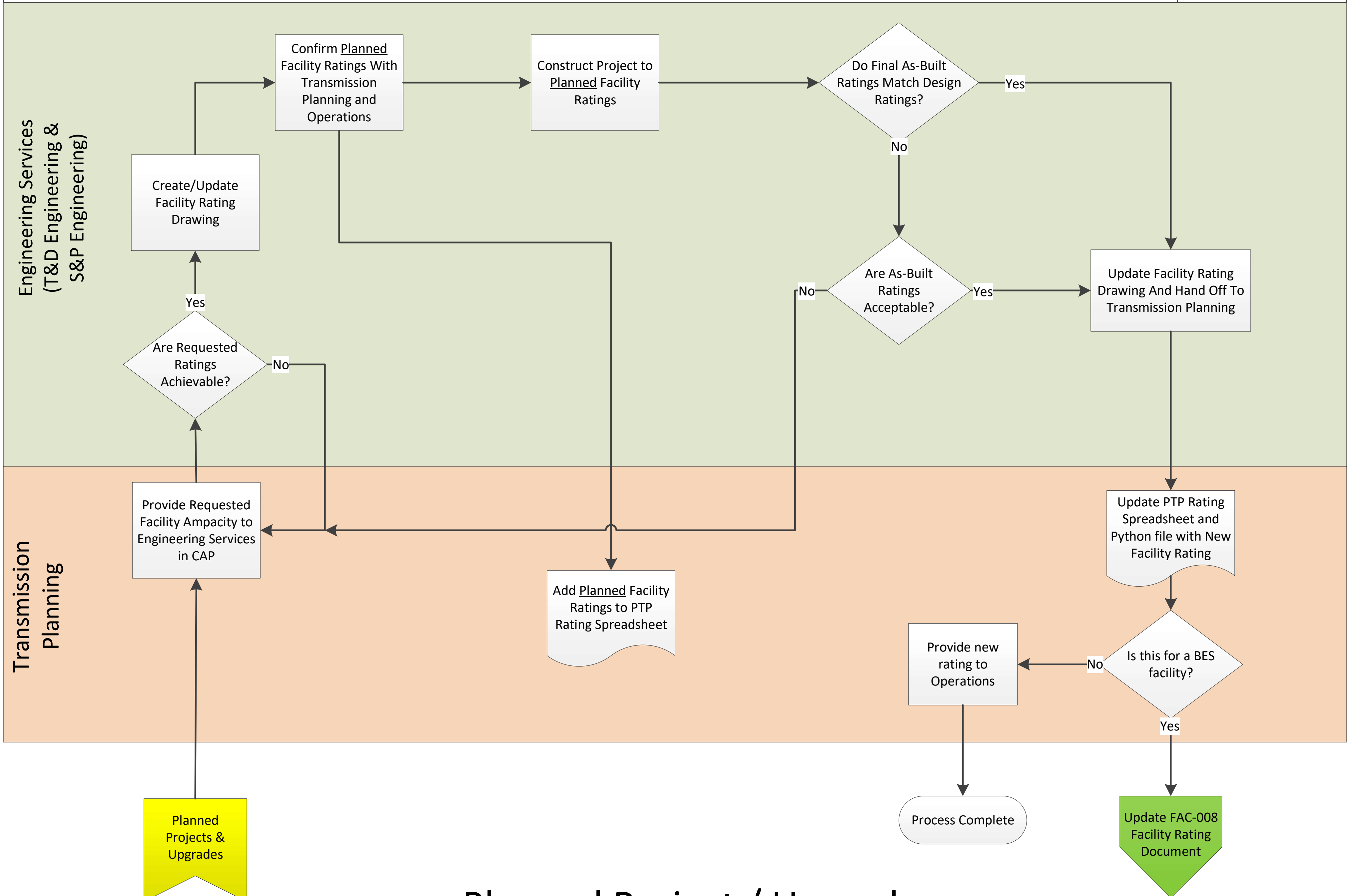
# BHC Transmission Owner Facility Rating Process (FAC-008-5)

Owner: MRUNNER
Approved: LBRIGGS



# BHC Transmission Owner Facility Rating Process (FAC-008-5)

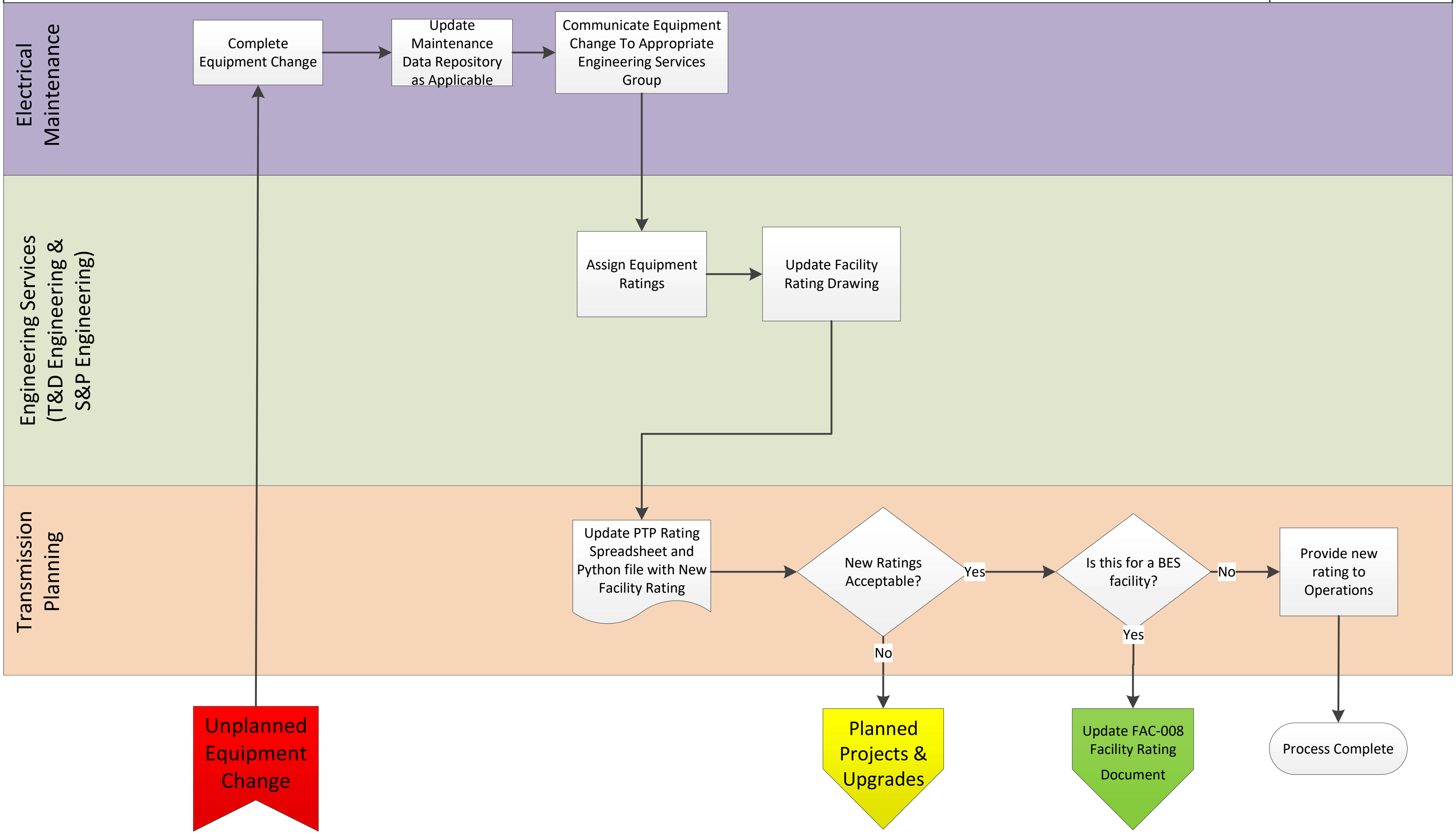
Owner: MRUNNER
Approved: LBRIGGS




## Planned Project / Upgrade

# BHC Transmission Owner Facility Rating Process (FAC-008-5)

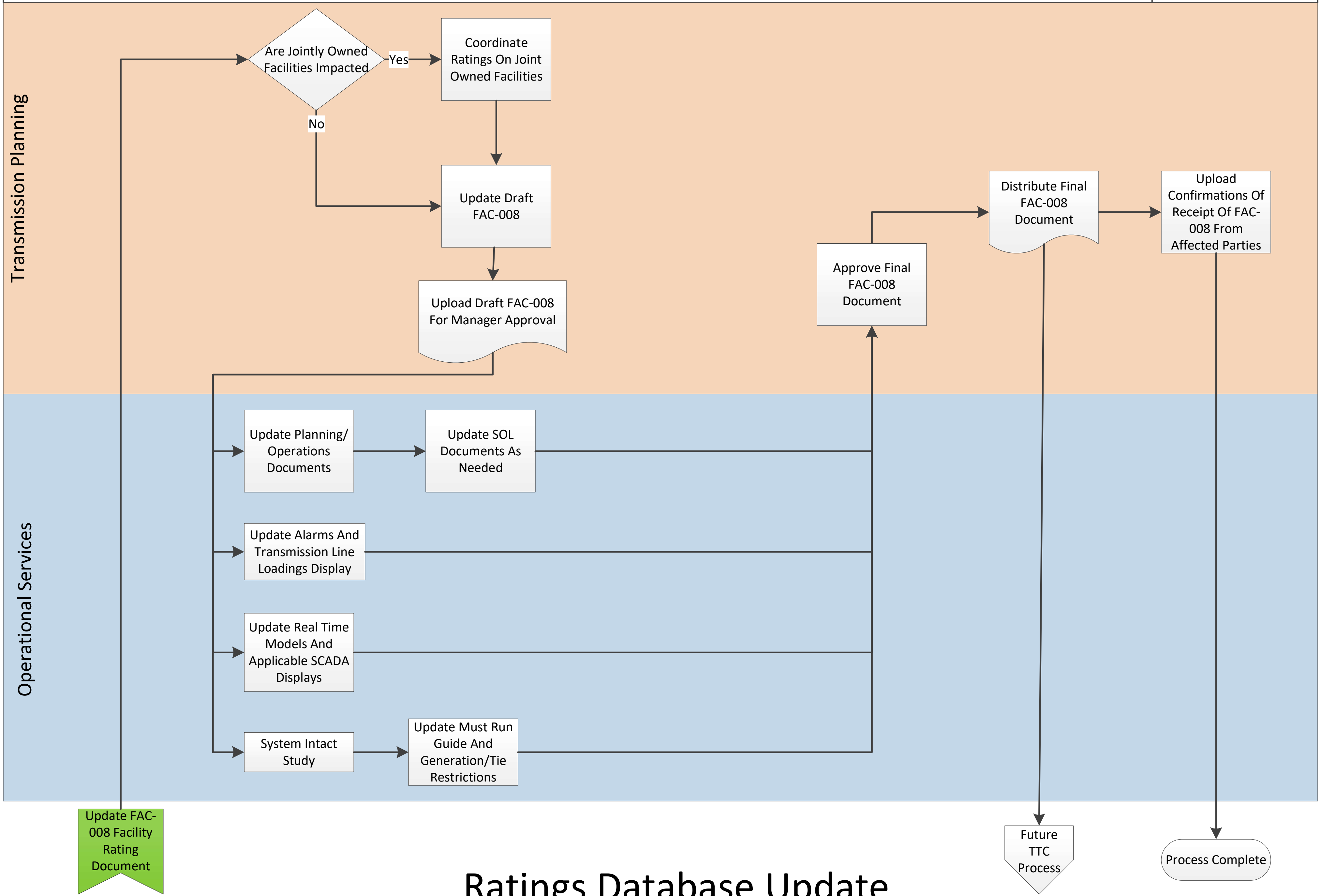
Owner: MRUNNER
Approved: LBRIGGS




## Unplanned Equipment Change

# BHC Transmission Owner Facility Rating Process (FAC-008-5)

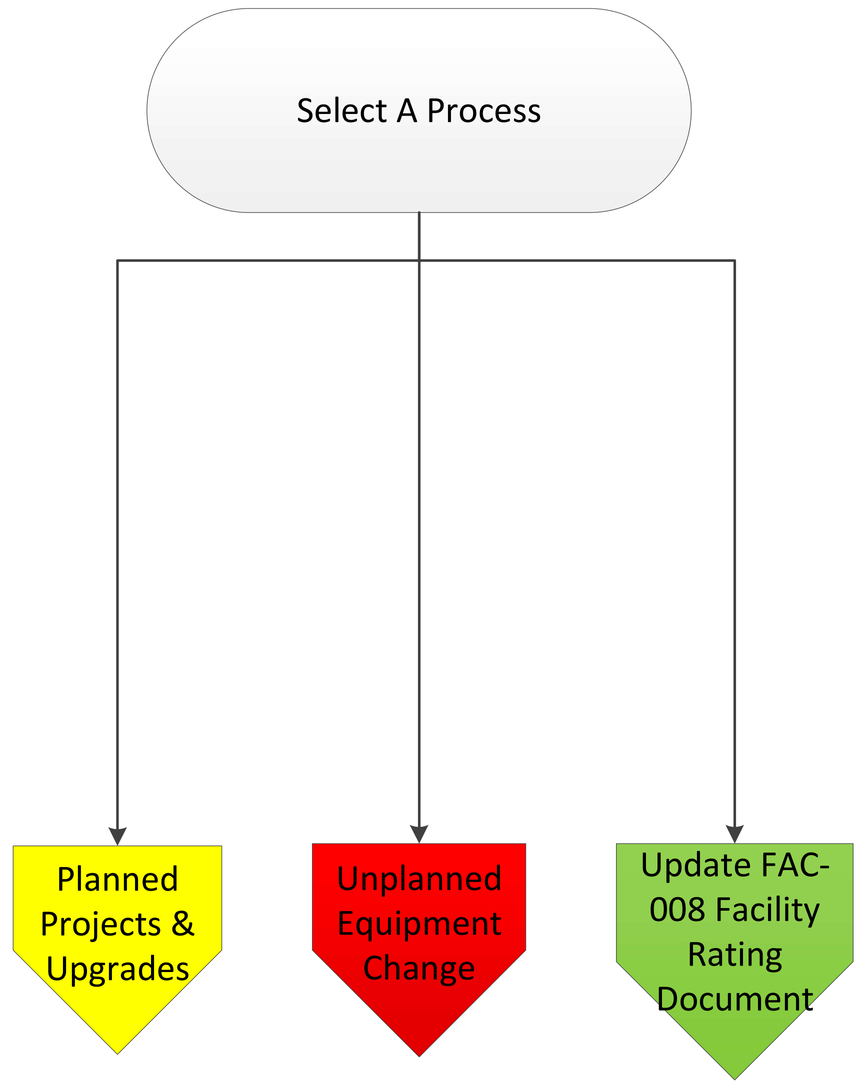
Owner: MRUNNER
Approved: LBRIGGS




## Ratings Database Update

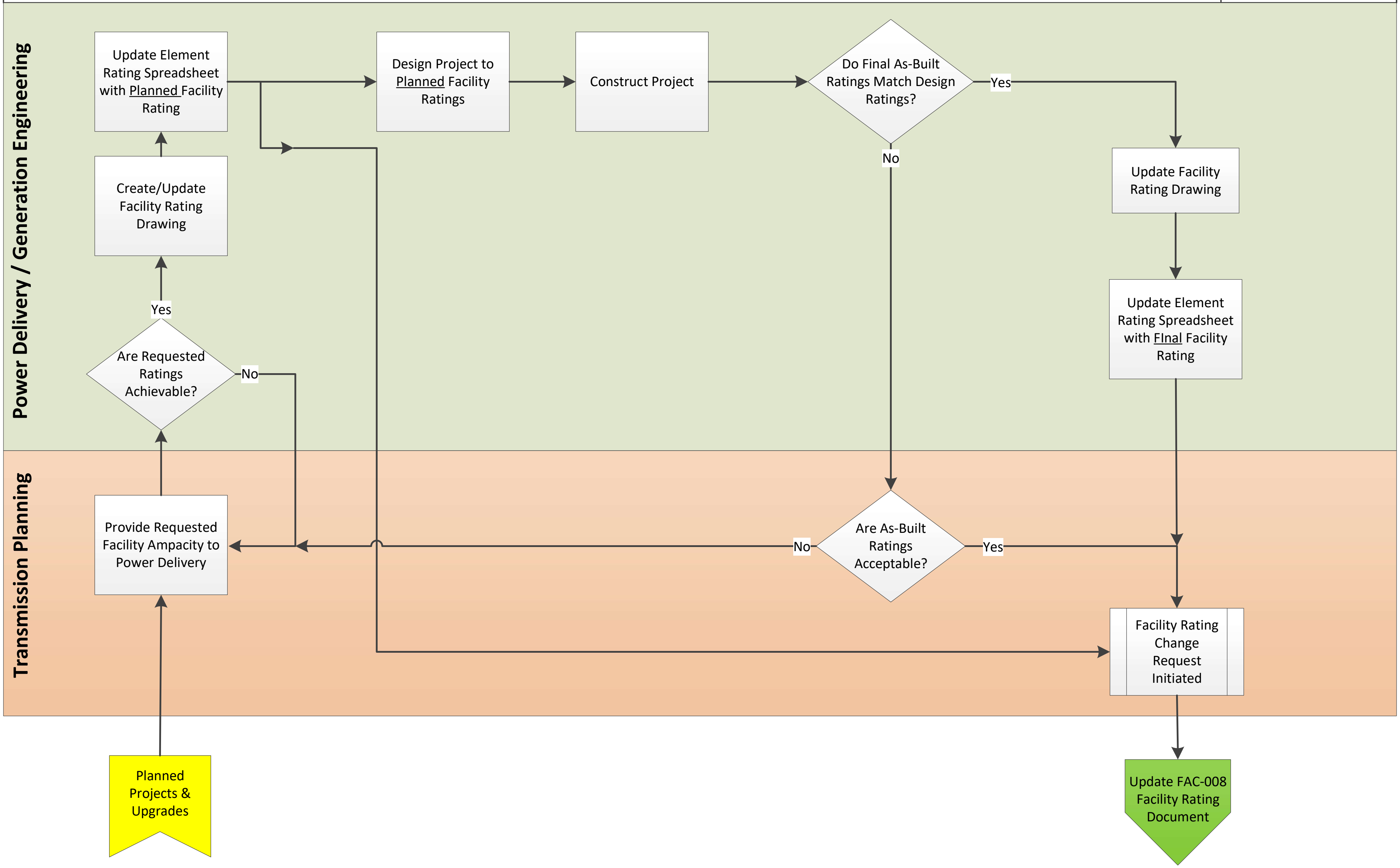
# BHC Generator Owner Facility Rating Process (FAC-008-5)

Owner: MRUNNER
Approved: SSUURMEIER



# BHC Generator Owner Facility Rating Process (FAC-008-5)

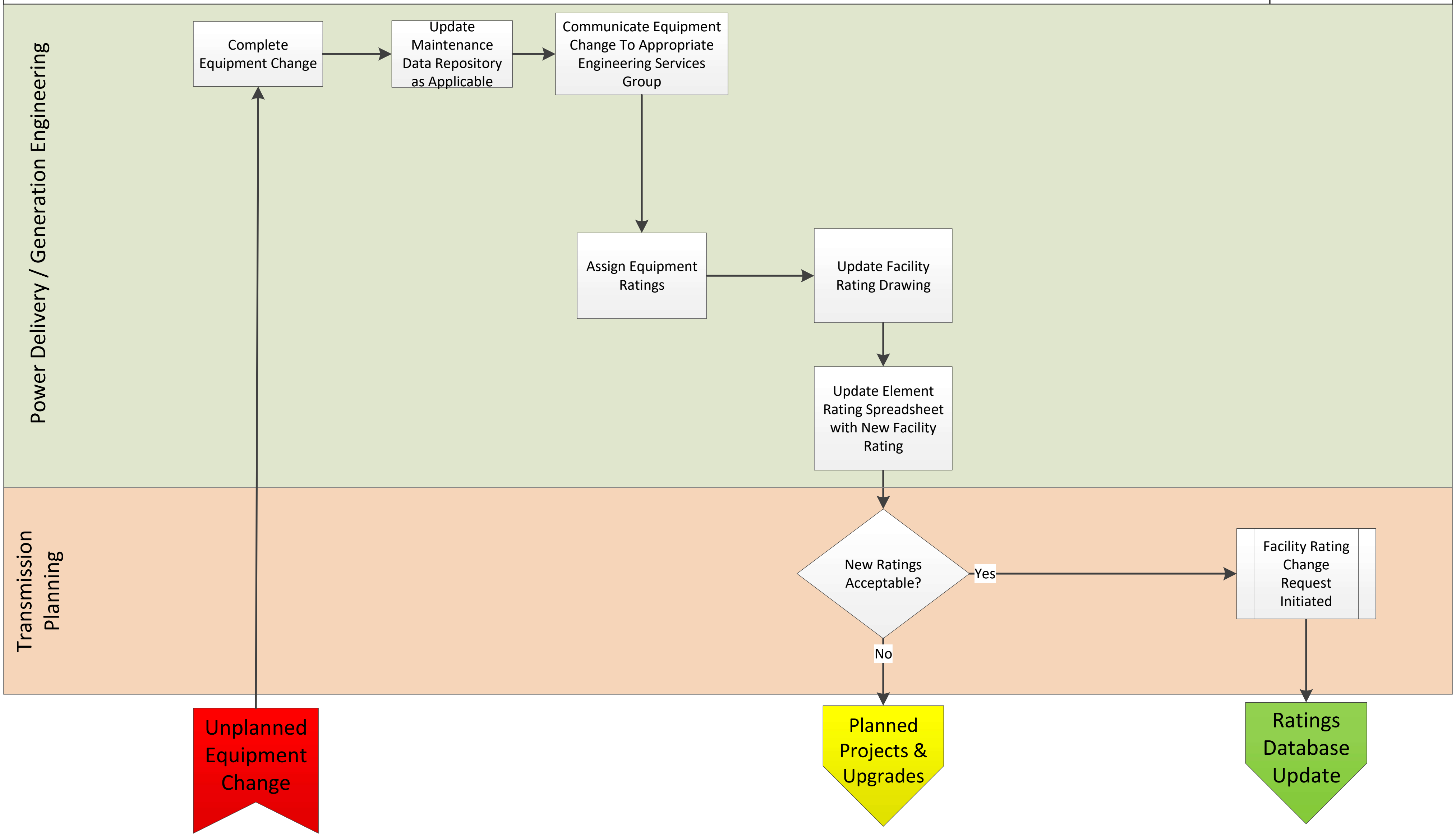
Owner: MRUNNER
Approved: SSUURMEIER




# Planned Projects / Upgrades

# BHC Generator Owner Facility Rating Process (FAC-008-5)

Owner: MKUNNER
Approved: SSUURMEIER




## Unplanned Equipment Change

# BHC Generator Owner Facility Rating Process (FAC-008-5)

Owner: MRUNNER
Approved: SSUURMEIER