2018 Resource Planning

Generation and Storage Resource Characterizations

October 19, 2018

HDR Project #10103432

Revision 4

2018 RESOURCE PLANNING
GENERATION AND STORAGE RESOURCE CHARACTERIZATIONS
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EXECUTIVE SUMMARY

NorthWestern Energy (NorthWestern) is preparing its 2018 Energy Supply Resource Procurement Plan (2018 Plan) for the states of Montana and South Dakota, which includes the evaluation of thermal, renewable, and energy storage technologies. HDR Engineering, Inc. (HDR) was retained by NorthWestern to assist with the overall 2018 Plan effort by characterizing the operational and cost attributes of various power generation and energy storage technologies. This information is intended to support dispatch modeling and portfolio optimization as a means of evaluating and comparing procurement scenarios for the 2018 Plans. The parameters developed for each technology include estimated performance and operating characteristics, capital costs, operating costs, and implementation schedules. The range of technologies considered include several natural gas fired generating options, renewable technologies, and energy storage technologies. The resulting parameters for the various technologies are summarized in Tables E-1, E-2, and E-3 for representative project sites within the western Montana, eastern Montana, and South Dakota regions, respectively. The following summarizes the basis for development of the parameters for each of the technologies.

1. Performance has been estimated for all options based on supplier feedback and performance estimating software.
2. Conceptual level project capital costs have been developed based on an overnight, turnkey engineer, procure, construct (EPC) delivery in 2018 dollars. Additionally, potential future resource cost trends have been identified.
3. Conceptual level operations and maintenance (O&M) costs, including both fixed and variable O&M, were estimated and are presented in $/kW-yr and $/MWh, respectively.
4. Conceptual level project implementation schedules identifying key project milestones and duration of key project activities from EPC contractor notice to proceed (NTP) to the commercial operation date (COD) are presented.
5. Input parameters for dispatch modeling were derived from the O&M costs and operating characteristics for each option.

Additional details and results regarding the development of the 2018 Plan inputs are further summarized in this report. The inputs and information developed for the 2018 Plan activities are intended to represent the current energy industry landscape and are based on supplier-, site-, and project-generic technologies. Technology attributes are suitable for comparative purposes, should not be used for budget planning purposes, and are subject to refinement based on further evaluation and review.

Table E-1. Summary of Technology Attributes for Western Montana

Western Montana	Fuel	Nameplate Capacity (Nominal)	Design Life	Net Output - Winter	Net Heat Rate - Winter (HHV)[1]	Capital Cost[2]	Capacity Factor[3]	Fixed O&M (Yr 1)	Variable O&M (Yr 1)	Project Schedule (NTP to COD)
Technology	**(Type)**	**(MW)**	**(Years)**	**(MW)**	**(Btu/kWH)**	**($/kW)**	**(%)**	**($/kW-yr)**	**($/MWH)**	**(months)**
Combustion Turbine - Dry Cooling										
Simple Cycle 1x0 CT - 50 MW Frame	NG	48.1	30	45.8	9,986	$1,433	14.8%	$13.18	$8.73	22
Simple Cycle 1x0 CT - 25 MW Aeroderivative	NG	28.1	30	26.7	9,902	$1,659	14.8%	$20.42	$5.58	22
Simple Cycle 1x0 CT - 50 MW Aeroderivative	NG	47.4	30	45.2	9,388	$1,336	14.8%	$13.38	$4.38	22
Simple Cycle 1x0 CT - 50 MW Aeroderivative (NG / Fuel Oil)[4]	NG / Fuel Oil	47.2	30	45.0	9,426	$1,491	11.8% / 3%	$13.81	$5.13	22
Simple Cycle 1x0 CT - 50 MW Aeroderivative (NG/LNG)[4]	NG / LNG	47.4	30	45.2	9,418	$1,780	11.8% / 3%	$13.88	$4.73	22
Combined Cycle 2x1 CT - Frame/Industrial CT	NG	133.3	30	127.0	7,210	$1,323	47.0%	$25.75	$6.30	36
Combined Cycle 2x1 CT - Frame/Industrial CT w/ DB - Unfired	NG	133.3	30	126.9	7,221	$1,385	47.0%	$25.85	$6.31	36
Combined Cycle 2x1 CT - Frame/Industrial CT w/ DB - Fired	NG	151.9	30	144.6	7,533	$1,215	47.0%	$22.69	$5.55	36
Reciprocating Internal Combustion Engine										
Simple Cycle 1x0 RICE - 18 MW Class NG Only	NG	19.4	30	18.5	8,329	$1,833	14.8%	$23.26	$4.68	18
Simple Cycle 1x0 RICE - 18 MW Class NG Only (NG / LNG)[4]	NG / LNG	19.4	30	18.5	8,357	$2,149	11.8% / 3%	$23.62	$4.99	18
Simple Cycle 1x0 RICE - 18 MW Class Dual Fuel	NG	17.9	30	17.0	8,463	$2,080	14.8%	$25.31	$5.77	18
Simple Cycle 1x0 RICE - 18 MW Dual Fuel (NG / Fuel Oil)[4]	NG / Fuel Oil	17.4	30	16.5	8,503	$2,075	11.8% / 3%	$29.70	$6.57	18
Simple Cycle 1x0 RICE - 9 MW Class NG Only	NG	9.6	30	9.2	8,103	$2,324	14.8%	$54.62	$4.55	18
Wind Energy										
Wind Energy	N/A	105.0	25	100.0	N/A	$1,410	41.1%	$37.00	N/A	24
Solar Photovoltaic (PV)										
Solar PV - Single Axis Tracking	N/A	105.0	20	100.0	N/A	$1,330	24.2%	$21.60	N/A	14-22
Geothermal										
Geothermal - Flash Steam	N/A	21.0	30	20.0	1,000	$2,800	95.0%	$123.98	$9.88	36
Pumped Hydro Energy Storage (PHES)										
PHES - Closed Loop (9 Hour)	Elec. Grid	525.0	30	500.0	N/A	$1,700-$3,000	37.1%	$14.55	$0.90	60-96
Compressed Air Energy Storage (CAES)										
CAES - Diabatic (8 Hour)	Elec. Grid / NG	105.0	30	100.0	4,500	$1,500-$2,300	33.0%	$15.27	$8.53	24
Battery Energy Storage System (BESS)										
BESS - Lithium Ion (4 Hour)	N/A	26.3	20	25.0	N/A	$1,660	16.6%	$39.61	$7.00	14
BESS - Vanadium Flow (4 Hour)	N/A	26.3	20	25.0	N/A	$1,700	16.6%	$34.01	N/A	14

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1 Thermal heat rates are presented on a higher heating value (HHV) basis.
2 $/kW capital cost metrics divide estimated project costs by the net winter output for a given technology.
3 Capacity factors for dispatchable technologies assumed in order to develop O&M costs.
4 Dual fuel performance and costs are presented as a blend of NG and alternative fuel (NG or FO) operations (1,034 hours on NG and 263 hours on alternative fuel).

Table E-2. Summary of Technology Attributes for Eastern Montana[5]

Eastern Montana	Fuel	Nameplate Capacity (Nominal)	Design Life	Net Output - Winter	Net Heat Rate - Winter (HHV)	Capital Cost	Capacity Factor	Fixed O&M (Yr 1)	Variable O&M (Yr 1)	Project Schedule (NTP to COD)
Technology	**(Type)**	**(MW)**	**(Years)**	**(MW)**	**(Btu/kWH)**	**($/kW)**	**(%)**	**($/kW-yr)**	**($/MWH)**	**(months)**
Combustion Turbine - Dry Cooling										
Simple Cycle 1x0 CT - 50 MW Frame	NG	51.4	30	48.9	9,970	$1,361	14.8%	$12.52	$8.30	22
Simple Cycle 1x0 CT - 25 MW Aeroderivative	NG	30.5	30	29.1	9,921	$1,547	14.8%	$19.03	$5.37	22
Simple Cycle 1x0 CT - 50 MW Aeroderivative	NG	49.6	30	47.3	9,369	$1,276	14.8%	$12.78	$4.05	22
Simple Cycle 1x0 CT - 50 MW Aeroderivative (NG / Fuel Oil)	NG / Fuel Oil	49.4	30	47.1	9,407	$1,425	11.8% / 3%	$13.19	$4.72	22
Simple Cycle 1x0 CT - 50 MW Aeroderivative (NG/LNG)	NG / LNG	49.6	30	47.3	9,399	$1,700	11.8% / 3%	$13.26	$4.38	22
Combined Cycle 2x1 CT - Frame/Industrial CT	NG	140.2	30	133.5	7,213	$1,259	47.0%	$24.49	$5.99	36
Combined Cycle 2x1 CT - Frame/Industrial CT w/ DB - Unfired	NG	140.6	30	133.9	7,192	$1,312	47.0%	$24.50	$6.00	36
Combined Cycle 2x1 CT - Frame/Industrial CT w/ DB - Fired	NG	159.6	30	152.0	7,530	$1,157	47.0%	$21.60	$5.31	36
Reciprocating Internal Combustion Engine										
Simple Cycle 1x0 RICE - 18 MW Class NG Only	NG	19.4	30	18.5	8,318	$1,833	14.8%	$23.07	$4.64	18
Simple Cycle 1x0 RICE - 18 MW Class NG Only (NG / LNG)	NG / LNG	19.4	30	18.5	8,356	$2,149	11.8% / 3%	$23.43	$4.99	18
Simple Cycle 1x0 RICE - 18 MW Class Dual Fuel	NG	17.9	30	17.0	8,505	$2,017	14.8%	$25.10	$5.73	18
Simple Cycle 1x0 RICE - 18 MW Dual Fuel (NG / Fuel Oil)	NG / Fuel Oil	17.4	30	16.5	8,545	$2,075	11.8% / 3%	$29.45	$6.53	18
Simple Cycle 1x0 RICE - 9 MW Class NG Only	NG	9.6	30	9.2	8,103	$2,306	15.0%	$54.20	$4.52	18
Wind Energy										
Wind Energy	N/A	105.0	25	100.0	N/A	$1,410	44.4%	$37.00	N/A	24
Solar Photovoltaic (PV)										
Solar PV - Single Axis Tracking	N/A	105.0	20	100.0	N/A	$1,330	24.5%	$21.60	N/A	14-22
Geothermal										
Geothermal - Flash Steam	N/A	21.0	30	20.0	1,000	$2,800	95.0%	$123.98	$9.88	36
Pumped Hydro Energy Storage (PHES)										
PHES - Closed Loop (9 Hour)	Elec. Grid	525.0	30	500.0	N/A	$1,700-$3,000	37.1%	$14.55	$0.90	60-96
Compressed Air Energy Storage (CAES)										
CAES - Diabatic (8 Hour)	Elec. Grid / NG	105.0	30	100.0	4,500	$1,500-$2,300	33.0%	$15.27	$8.53	24
Battery Energy Storage System (BESS)										
BESS - Lithium Ion (4 Hour)	N/A	26.3	20	25.0	N/A	$1,660	16.6%	$39.61	$7.00	14
BESS - Vanadium Flow (4 Hour)	N/A	26.3	20	25.0	N/A	$1,700	16.6%	$34.01	N/A	14

5 Refer to notes for Table E-1.

Table E-3. Summary of Technology Attributes for South Dakota[6][7][8]

South Dakota	Fuel	Nameplate Capacity (Nominal)	Design Life	Net Output - Summer	Net Heat Rate - Summer (HHV)	Capital Cost	Capacity Factor	Fixed O&M (Yr 1)	Variable O&M (Yr 1)	Project Schedule (NTP to COD)
Technology	**(Type)**	**(MW)**	**(Years)**	**(MW)**	**(Btu/kWH)**	**($/kW)**	**(%)**	**($/kW-yr)**	**($/MWH)**	**(months)**
Combustion Turbine - Dry Cooling										
Simple Cycle 1x0 CT - 50 MW Frame	NG	49.3	30	47.0	10,087	$1,398	14.8%	$12.93	$7.62	22
Simple Cycle 1x0 CT - 25 MW Aeroderivative	NG	27.4	30	26.1	10,350	$1,702	14.8%	$20.94	$4.91	22
Simple Cycle 1x0 CT - 50 MW Aeroderivative	NG	50.6	30	48.2	9,615	$1,252	14.8%	$12.54	$3.72	22
Simple Cycle 1x0 CT - 50 MW Aeroderivative (NG / Fuel Oil)	NG / Fuel Oil	50.4	30	48.0	9,654	$1,397	11.8% / 3%	$12.95	$4.31	22
Simple Cycle 1x0 CT - 50 MW Aeroderivative (LNG)	NG / LNG	50.6	30	48.2	9,645	$1,692	11.8% / 3%	$13.01	$4.04	22
Combined Cycle 2x1 CT - Frame/Industrial CT	NG	138.0	30	131.5	7,208	$1,280	47.0%	$24.87	$5.99	36
Combined Cycle 2x1 CT - Frame/Industrial CT w/ DB - Unfired	NG	137.9	30	131.3	7,216	$1,339	47.0%	$24.99	$5.51	36
Combined Cycle 2x1 CT - Frame/Industrial CT w/ DB - Fired	NG	156.1	30	148.6	7,529	$1,182	47.0%	$22.08	$4.88	36
Reciprocating Internal Combustion Engine										
Simple Cycle 1x0 RICE - 18 MW Class NG Only	NG	19.4	30	18.5	8,409	$1,833	14.8%	$23.07	$4.65	18
Simple Cycle 1x0 RICE - 18 MW Class NG Only (NG / LNG)	NG / LNG	19.4	30	18.5	8,438	$2,149	11.8% / 3%	$23.43	$4.99	18
Simple Cycle 1x0 RICE - 18 MW Class Dual Fuel	NG	17.9	30	17.0	8,553	$2,017	14.8%	$25.10	$5.73	18
Simple Cycle 1x0 RICE - 18 MW Dual Fuel (NG / Fuel Oil)	NG / Fuel Oil	17.4	30	16.5	8,593	$2,075	11.8% / 3%	$29.45	$6.53	18
Simple Cycle 1x0 RICE - 9 MW Class NG Only	NG	9.6	30	9.2	8,119	$2,306	14.8%	$54.20	$4.57	18
Wind Energy										
Wind Energy	N/A	105.0	25	100.0	N/A	$1,407	44.4%	$37.00	N/A	24
Solar Photovoltaic (PV)										
Solar PV - Single Axis Tracking	N/A	105.0	20	100.0	N/A	$1,330	24.1%	$21.60	N/A	14-22
Geothermal										
Geothermal - Flash Steam	N/A	21.0	30	20.0	1,000	$2,800	95.0%	$123.98	$9.88	36
Compressed Air Energy Storage (CAES)										
CAES - Diabatic (8 Hour)	Elec. Grid / NG	105.0	30	100.0	4,500	$1,500-$2,300	33.0%	$15.27	$8.53	24
Battery Energy Storage System (BESS)										
BESS - Lithium Ion (4 Hour)	N/A	26.3	20	25.0	N/A	$1,660	16.6%	$39.61	$7.00	14
BESS - Vanadium Flow (4 Hour)	N/A	26.3	20	25.0	N/A	$1,700	16.6%	$34.01	N/A	14

6 Refer to notes for Table E-1 (except for note regarding $/kW metrics – see below).
7 $/kW capital cost metrics divide estimated project costs by the net summer output for a given technology.
8 PHES is not considered in the South Dakota resource planning activities.

1.0 INTRODUCTION

NorthWestern Energy (NorthWestern) is preparing its 2018 Energy Supply Resource Procurement Plan (2018 Plan) for the states of Montana and South Dakota[9]. NorthWestern is evaluating several types of resources including thermal, renewable, and energy storage technologies. HDR Engineering, Inc. (HDR) was retained by NorthWestern to assist with the characterization of the power generation and energy storage technologies to be considered in the 2018 Plan work. This evaluation focuses on supply side alternatives, with NorthWestern considering demand side alternatives separately. These characterizations resulted in the development of modeling parameters and assumptions intended to be used in further dispatch modeling and portfolio evaluation for NorthWestern's 2018 Plans. Technology characteristics presented include estimated performance and operating characteristics, capital costs, operations and maintenance (O&M) costs, and implementation schedules for several natural gas-fired generating technologies, renewable technologies, and energy storage options. This report summarizes the assumptions utilized and basis of approach to develop the characteristics for each technology. In addition, information on current market conditions that may influence the accuracy of the parameters or impact the ability of NorthWestern to implement the technologies considered is also discussed.

1.1 RESOURCE OPTIONS

In total, the following 14 power generation and energy storage resource options were considered. Unless otherwise indicated, the thermal technologies are assumed to utilize natural gas fuel only[10].

1. Simple Cycle 1x0 Combustion Turbine (CT) – 50 MW Frame
2. Simple Cycle 1x0 CT – 25 MW Aeroderivative
3. Simple Cycle 1x0 CT – 50 MW Aeroderivative
    a. Natural gas only
    b. Natural gas + diesel fuel backup
    c. Natural gas + liquefied natural gas (LNG) fuel backup
4. Combined Cycle 2x1 CT – Frame CT (Unfired)
5. Combined Cycle 2x1 CT – Frame CT (Fired)
6. Simple Cycle 1x0 Reciprocating Internal Combustion Engine (RICE) – 18 MW Class
    a. Natural gas only
    b. Natural gas + diesel fuel backup
    c. Natural gas + LNG fuel backup
7. Simple Cycle 1x0 RICE generator– 9 MW Class

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[9] In both Montana and South Dakota, NorthWestern's integrated resource planning (IRP) process is referred to as their Electric Supply Resource Procurement Plan (ESRPP).

[10] For the thermal options, carbon capture and sequestration (CCS) is not considered. However, this report does include a brief characterization of CCS and the current status of the technology.

8. Solar Photovoltaic (PV) – 100 MW solar PV generation facility
9. Wind – 100 MW wind generation facility
10. Geothermal – 20 MW generation facility
11. Pumped Hydro Energy Storage (PHES) – 500 MW with 9 hours of storage
12. Compressed Air Energy Storage (CAES) – 100 MW with 8 hours of discharge
13. Battery Energy Storage System (BESS) – 25 MW lithium ion (Li-ion) with 4 hours of storage
14. BESS – 25 MW vanadium flow with 4 hours of storage

PHES is not considered in the South Dakota planning process. All other technologies listed are evaluated for both Montana and South Dakota.

1.2 ACRONYMS

The following acronyms are listed for reference and are used throughout this report.

Term	Definition
ACC	Air cooled condenser
AMSL	Above mean sea level
ASHRAE	American Society of Heating, Refrigeration, and Air-Conditioning Engineers
BESS	Battery energy storage system
Btu	British thermal units
CAES	Compressed air energy storage
CC	Combined cycle
CCS	Carbon capture and sequestration
CO	Carbon monoxide
CO_2	Carbon dioxide
COD	Commercial operation date
COG	Cost of generation
CT	Combustion turbine
DB	Duct burner
DLN	Dry-low NO_x
EIA	Energy Information Administration
EPC	Engineer, Procure, Construct
EOR	Enhanced oil recovery
ESRPP	Electricity Supply Resource Procurement Plan
FERC	Federal Energy Regulatory Commission

FO	Fuel oil (diesel)
G&A	General and administrative (costs)
GHGs	Greenhouse gases
GPM	Gallons per minute
GSU	Generator step-up (transformer)
HHV	Higher heating value
HRSG	Heat recovery steam generator
kW	Kilowatt
LCOG	Levelized cost of generation
LHV	Lower heating value
Li-ion	Lithium ion (battery technology)
LNG	Liquefied natural gas
mmBtu	Million British thermal units
MW	Megawatt
MWh	Megawatt-hour
NCF	Net capacity factor
NO_x	Oxides of nitrogen
NREL	National Renewable Energy Laboratory
NTP	Notice to Proceed
O&M	Operations and maintenance
OEM	Original equipment manufacturer
PCC	Post-combustion capture
PHES	Pumped hydro energy storage
PM	Particulate matter
ppm	Parts per million
psi	Pounds per square inch
PV	Photovoltaic (solar technology)
RICE	Reciprocating internal combustion engine
RFP	Request for proposals
SC	Simple cycle
SCR	Selective catalytic reduction
SEIA	Solar Energy Industries Association

2.0 BASIS OF EVALUATION

The purpose of this evaluation is to develop conceptual operational and cost attributes for a variety of generation and storage technologies. As the technologies evaluated in the 2018 Plans are not project-, location-, or technology supplier-specific, development of the technology attributes is based on a variety of generic inputs and assumptions and is focused on being representative of current market offerings. This Section provides the overall basis and assumptions considered in developing technology characteristics, and is supplemented with additional specific considerations in the technology Sections following.

2.1 SITE CHARACTERISTICS

The technologies evaluated in this report are assumed to be located at three distinct sites within NorthWestern's Montana and South Dakota service territories. The three locations are assumed to be greenfield sites and located in the following areas:

- Western Montana
- Eastern Montana
- South Dakota

Summer, average, and winter day ambient conditions for each of the three locations were determined based on ASHRAE 2017 climate data for proxy sites in each region. These ambient conditions as well as assumed proxy site elevations are outlined in Table 2.1-1 below.

Table 2.1-1. Assumed Site Conditions

Ambient Conditions		Western MT	Eastern MT	South Dakota
Elevation	ft. ASML	5,200	3,500	1,300
Summer				
Dry Bulb Temperature	deg. F	88.0	94.7	94.1
Wet Bulb Temperature	deg. F	58.0	62.7	73.7
Relative Humidity	%	16.5%	17.7%	40.7%
Average				
Dry Bulb Temperature	deg. F	40.0	48.3	47.0
Wet Bulb Temperature	deg. F	34.0	41.6	40.9
Relative Humidity	%	57.5%	60.0%	62.5%
Winter				
Dry Bulb Temperature	deg. F	20.0	28.2	15.0
Wet Bulb Temperature	deg. F	18.0	24.2	12.7
Relative Humidity	%	73.6%	60.0%	64.1%

For wind generation, an additional site in central Montana was considered in order to evaluate potential wind resource variance across the state.

2.2 TECHNOLOGY SUPPLIERS

This evaluation considers generic technology types and size classes in order to provide a representation of the current supplier marketplace. The performance and cost characteristics developed for this effort consider feedback from suppliers (through budgetary proposals and discussion), publicly available information, and data and information from previous developments and projects. The performance and cost characteristics consider a variety of supplier inputs, are intended to be representative, and are not intended to suggest a specific technology supplier is preferred by NorthWestern over another. Many capable suppliers exist for a given technology and, if a given technology were developed, suppliers would be vetted through a competitive request for proposal (RFP) process.

2.3 BASIS OF DESIGN/COST BASIS

This evaluation considers typical utility-grade design considerations, contracting, and execution methods for the various technologies under consideration. The parameters developed as part of this effort do not consider significant conceptual design but are considered to be representative of as-built projects in today's marketplace. No detailed design has taken place and site-specific influences are not considered other than ambient conditions, site elevation, and labor markets.

The conceptual project costs developed for this evaluation consider an engineer, procure, construct (EPC) project delivery and account for "inside-the-fence" project scope and associated costs. Generally, the project costs consider a contractor scope of supply up to a defined point of scope demarcation, beyond which point any additional scope would need to be considered in the Owner's costs, which are not estimated herein.

As applicable, costs associated with natural gas radial lines from supply pipelines are not accounted for in this evaluation – assumptions for natural gas supply capacity and pressure delivered to the site serve as the basis for the "inside-the-fence" scope of supply. Electric scope of supply generally breaks at the high side of the generator step-up (GSU) transformer and does not include substation/switchgear facilities required for interconnection to the bulk electric grid or network upgrades on the electric grid associated with the interconnection. Municipal or other interconnections for water supply and/or wastewater discharge are assumed at the site boundary. The "outside-the-fence" costs are not included in the project cost estimates developed for this effort (investigated separately by NorthWestern).

2.4 PLANT PERFORMANCE

2.4.1 Performance

Plant performance (i.e. output, efficiency, etc.) was estimated for all technologies based on performance estimating software, previous project developments, feedback from suppliers, and/or published performance information.

For the thermal generation options, performance was developed based on prime mover performance provided by original equipment manufacturers (OEMs), ThermoFlow performance estimating software, and development of facility auxiliary loads. Performance was developed for summer, average, and winter day ambient conditions at full and part load operating conditions.

For the wind and solar technologies, estimated net capacity factors (NCFs) were developed utilizing performance estimating software made available by the National Renewable Energy Laboratory (NREL). Performance for other alternatives was estimated based on feedback from suppliers, current marketplace benchmarking, and previous project developments.

2.4.2 Air Emissions

For the thermal technologies, plant air emissions were estimated at steady-state, full load operation based on supplier-provided emission profiles and assumed fuel characteristics. Emissions estimated for this evaluation are not intended to be used for permitting activities and are intended to provide a comparison between the different thermal technologies. When discharging, emissions for CAES are anticipated to be similar to a simple cycle CT on a lb/mmBtu basis given the combustion of natural gas. Air emissions for other technologies are expected to be minimal.

2.4.3 Water Resources

Plant water consumption and wastewater discharge were estimated for the thermal technologies based on conceptual plant water management systems typical of the technology evaluated.

An allocation is included in the O&M costs for panel wash water for the solar PV alternative. Evaporative losses from the reservoir were not estimated for PHES and water replenishment for this technology is assumed to be from a nearby water resource and at minimal cost.

2.5 CONCEPTUAL COST ESTIMATES

Conceptual-level project capital costs were developed for each technology based on the following:

- Overnight, turnkey EPC delivery in 2018 dollars
- EPC contractor direct equipment and labor costs, construction and project indirect costs, and other fees and contingencies typical for EPC project delivery
- Project location within NorthWestern's service territory on a site/land generally suitable for development
- General adjustments for labor and wage rates based on location in Montana or South Dakota
- Electric scope of supply up to the high side of the GSU transformer (costs associated with grid interconnection and network upgrades excluded)
- Fuel supply provided to the site boundary (fuel supply pipeline costs excluded)
- Municipal and other interconnections assumed at the site fence/boundary

- Owner's costs are excluded including, as applicable, costs associated with project development, permitting, contracting, Owner's engineering support, required interconnections "outside-the-fence," interest during construction/allowance for funds used during construction (AFUDC), and others
- American Association of Cost Engineering International (AACE) Class 5 level of accuracy (L: -20% to -50%; H: +30% to +100%) suitable for comparative purposes
- Capital costs expressed in $/kW are based on the full load, winter day net electric output for Montana and full, load summer day net electric output for South Dakota (based on when each utility experiences its peak load)

Summaries of the conceptual project cost estimates associated with the thermal options are provided in Appendix A. Conceptual project costs for the other technologies are presented on a $/kW basis. All conceptual cost estimates developed for this effort consider the current power generation marketplace, feedback from equipment suppliers and contractors, publicly available information, and costs observed from previous project developments. Additionally, for reference, potential future resource costs trends were developed considering Energy Information Administration (EIA) forecast data. Discussion on potential cost trends is included in Section 10.

All costs presented herein are based on current day cost expectations, results of actual projects, and equipment budgetary quotations, where available. They are intended to reflect the current status of the industry with respect to recent materials and labor escalation. The estimates developed for this assessment are conceptual in nature, are for comparative and resource planning purposes only, and are not to be used for budget planning purposes. Any opinions of probable project cost or probable construction cost provided by HDR are made on the basis of information available to HDR and previous project experience. Since HDR has no control over the cost of labor, materials, equipment or services furnished by others, contractor's means and methods, or future market conditions, HDR does not warrant that proposals, bids, or actual project or construction costs will not vary from the costs provided herein.

2.6 CONCEPTUAL PROJECT IMPLEMENTATION SCHEDULES

A conceptual, site- and project-generic project implementation schedule was developed for each technology from contractor notice to proceed (NTP) through project commercial operation date (COD). These schedules do not consider project development activities ahead of contractor NTP such as feasibility and conceptual design, permitting, contracting, and regulatory activities.

These implementation schedules were developed based upon a review of key project milestones, construction activities, primary equipment lead times provided by OEMs, and experience on previous/similar applications. These schedules are considered conceptual in nature but represent a reasonable indication of timing of key activities throughout the execution of the project.

Conceptual project implementation schedules are included as Appendix B. Given significant site- and development-specific uncertainties associated with implementation durations for the PHES technology, an implementation schedule for this technology is not presented herein. However, an expected duration range is discussed.

2.7 CONCEPTUAL O&M COST ESTIMATES

Conceptual O&M costs were developed for each technology, considering fixed O&M costs and variable O&M costs, as applicable.

Fixed O&M costs are expenses required to operate and maintain a generation facility that are generally not dependent on electrical production/operation of the facility. Fixed O&M costs generally are inclusive of costs associated with staffing, fixed/recurring equipment O&M, spare parts inventory, building maintenance, and others. Staffing cost assumptions are summarized in the Table below.

Table 2.7-1. Staffing Cost Assumptions

Staffing Cost Assumptions	First Year Price (2018)
Annual Cost for Salaried Staff (Per Person)	$140,000
Annual Cost for Hourly Staff (Per Person)	$100,000

Fixed costs developed for this evaluation are presented on a $/kW-yr basis computed by dividing the estimated fixed annual O&M costs by the full load net plant output at winter day ambient conditions for Montana and at summer day ambient conditions for South Dakota. Fixed O&M costs presented herein do not include costs associated with insurances, property taxes, or corporate general and administrative (G&A) costs.

Variable O&M costs are those expenses that are dependent on electrical production/operation of a facility. Variable O&M costs presented herein generally are non-fuel variable O&M costs unless stated otherwise. Non-fuel variable O&M costs include costs associated with consumption and disposal of materials associated with operation, including water and wastewater, as well as variable costs associated with operating facility equipment, as applicable. Consumables unit cost assumptions are summarized in the Table below.

Table 2.7-2. Consumables Unit Cost Assumptions

Consumables	First Year Price (2018)
Escalation Rate	3.0%
Ammonia (As 19% NH3)	$166.52 / ton
Urea	$2.13 / kgal
Lube Oil	$9.00 / gal
Makeup Water	$1.50 / kgal
Demineralized Water	$3.50 / kgal
Waste Water Treatment	$1.00 / kgal

Variable O&M costs are presented herein on a $/MWh basis however, for some technologies, variable O&M costs can be broken down into electric production-based ($/MWh) and/or operation-based ($/hour of operation) costs.

2.8 DISPATCH MODELING INPUTS

Inputs for dispatch modeling were developed and formatted for use in the Ascend Analytics PowerSimm (PowerSimm) modeling software. Dispatch modeling inputs include the performance attributes and O&M costs previously discussed as well as additional operating attributes associated with each technology including startup/shutdown durations, ramp rates, turn down capability, charging considerations, and others. Dispatch modeling input parameters are provided for each option in Appendix C.

3.0 THERMAL GENERATION RESOURCE OPTIONS

3.1 TECHNOLOGY OVERVIEW

Thermal generation options considered in this evaluation include combustion turbine (CT) and reciprocating internal combustion engine (RICE) technologies in either simple cycle or combined cycle configuration. Both are commonly implemented technologies for utility scale power generation applications using pipeline natural gas as the primary fuel source.

Simple cycle CT plants are generally used to supply power during periods of peak electric demand (peaking power) due to their low capital cost, short construction schedule, rapid response (e.g. quick start capability), and ability to operate cost effectively at low capacity factors compared to other power generation alternatives.

Similar to simple cycle CT plants, simple cycle RICE installations are generally used to supply peaking power and to operate in load following scenarios. RICE technology is favorable for peaking applications due to its wide range of operability and rapid response capability. Generally, in utility power generation applications, RICE technology is smaller in scale and has better efficiency as compared to simple cycle CT technology. As compared to simple cycle CTs, RICE facilities are less susceptible to thermal performance variances due to changes in ambient conditions such as temperature and elevation.

A combined cycle facility involves the addition of a heat recovery steam generator (HRSG) to the exhaust of a CT or RICE unit[11] for the conversion of exhaust heat into steam that drives a steam turbine generator. The result is a significant increase in thermal efficiency over that of a simple cycle configuration. As compared to simple cycle technologies, the attributes of a combined cycle configuration include higher thermal efficiencies and less responsiveness in terms of starting and ramping, which make this technology more suitable for base load or intermediate load electrical supply.

Two of the simple cycle options considered in this analysis include the option to switch to a backup fuel in the event that the natural gas supply to the power generation facility is curtailed. Both the 50 MW aeroderivative simple cycle CT and the 18 MW simple cycle RICE were evaluated with backup fuel capabilities. Two different backup fuels were considered for these options: diesel fuel oil (FO) and liquefied natural gas (LNG). All other thermal options consider natural gas fuel only.

The following subsections provide a description of the various thermal generation resource options considered for this evaluation. None of the thermal generation resource options consider carbon capture and sequestration (CCS). However, a discussion of the current market status and general characteristics of CCS is included in Section 3.2.

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[11] While some applications do exist, RICE in combined cycle configuration are much less common than CTs in combined cycle configuration given lower exhaust energy associated with RICE units. As such, this evaluation does not consider RICE units in a combined cycle configuration.

3.1.1 Simple Cycle 1x0 CT – 50 MW Frame[12]

This option involves a nominal 50 MW frame-type gas turbine operating in a simple cycle configuration and considering natural gas fuel only. For this technology, an inlet air evaporative cooler is included and a selective catalytic reduction (SCR) system and oxidation catalyst are included for air emissions control.

3.1.2 Combined Cycle 2x1 CT – Frame CT (Unfired)[13]

The nominal 130 MW 2x1 combined cycle configuration consists of two nominally 50 MW frame CTs paired with dual pressure HRSG units. The HRSGs generate high and intermediate pressure steam using the hot exhaust gas from the CTs. This steam is fed to a single steam turbine generator to generate additional electrical output. The assumed configuration for this option uses an air cooled condenser (ACC) for thermal cycle heat rejection[14]. The turbines were also assumed to be equipped with inlet air evaporative coolers and SCR system/oxidation catalysts for emissions control in the HRSGs. This configuration does not consider HRSG supplemental duct firing (i.e. unfired configuration).

3.1.3 Combined Cycle 2x1 CT – Frame CT with Supplemental Firing

The nominal 150 MW 2x1 configuration is a derivative of the unfired combined cycle configuration described above but with the added feature of supplemental duct firing in the HRSGs. This configuration considers the same nominal 50 MW frame CTs. The increase in output is due to the additional steam generated from supplemental duct firing in the HRSGs and a larger steam turbine generator is assumed for the associated increased steam flow. This configuration offers the added flexibility of being able to cycle the duct burners on and off. Like the base unfired combined cycle option, this option considers an ACC for cycle heat rejection, employs CT inlet air evaporative coolers, and has an SCR system/oxidation catalysts for emissions control.

3.1.4 Simple Cycle 1x0 CT – 25 MW Aeroderivative

Aeroderivative CTs differ from their heavy duty frame counterparts in that their designs are derived from aircraft engines. These CTs are especially well-suited for peaking applications given short start times and rapid ramp rates. Aeroderivative turbines are generally also able to handle a greater number of starts throughout their lifecycle. The nominal 25 MW aeroderivative CT option is assumed to operate in simple cycle, include an inlet air evaporative cooler, and an SCR system/oxidation catalyst for emissions control.

3.1.5 Simple Cycle 1x0 CT – 50 MW Aeroderivative (Gas, Diesel, LNG)

This option consists of a larger nominal 50 MW aeroderivative CT. The base option is a single simple cycle aeroderivative CT operating on natural gas fuel only. Both an

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[12] "1x0" refers to a configuration with a single prime mover (CT/RICE) and no heat recovery/steam turbine.
[13] "2x1" refers to a combined cycle configuration with two prime movers (CTs), two HRSGs, and a single steam turbine.
[14] Wet, mechanical draft cooling towers are often employed for thermal cycle heat rejection systems.

inlet air evaporative cooler and exhaust SCR system/oxidation catalyst are assumed. Two additional derivatives of this option were also reviewed considering the use of a secondary backup fuel. Both diesel fuel oil and LNG were considered as backup fuels for this technology.

The option to add diesel fuel backup capability involves the inclusion of a diesel storage tank, additional fuel forwarding pumps, and a modification of the CT to allow operation on both gaseous and liquid fuels. When operating on diesel fuel oil, the CT will experience derated output and efficiency.

Adding the option for LNG involves the addition of a cryogenic tank for storing the LNG, a re-gasifier which converts the LNG back to its original gaseous state, and a system for disposing of the LNG boil off during storage of the fuel. This configuration does not include a natural gas liquefaction plant (LNG assumed to be trucked in). When operating on LNG supply, the turbine output and efficiency are similar to that when the CT is operating on natural gas. This is because the fuel is supplied in its gaseous state. Equipping a facility with LNG storage tends to be more complicated and, as a result, has higher capital cost than when utilizing diesel fuel oil as a back-up fuel supply.

3.1.6 Simple Cycle 1x0 RICE – 18 MW Class (Gas, Diesel, LNG)

This option considers a single nominal 18 MW RICE burning natural gas as a primary fuel. The engine is assumed to have an SCR system/oxidation catalysts for emissions reduction and engine cooling is achieved with fin-fan radiators. Like the 50 MW aeroderivative CT described above, this technology is also reviewed with secondary back-up fuel. Both diesel fuel oil and LNG are assumed as backup fuels. Because of the inherent differences in the dual fuel machine relative to the single fuel engines, the dual fuel engines have a lower output and efficiency compared to the gas-only models. Where the gas-only option considers spark ignition (with either natural gas or LNG), the dual fuel (NG/diesel) configuration considers compression ignition. As a result, the dual fuel (NG/diesel) configuration requires a liquid oil pilot system, even when operating on natural gas fuel.

The scope of supply for both the diesel fuel train and storage tank and the LNG fuel train and cryogenic storage tank are similar to what is described in the 50 MW aeroderivative CT discussion above.

3.1.7 Simple Cycle 1x0 RICE – 9 MW Class

This option considers a single 9 MW RICE operating on natural gas as the only fuel source. The engine is assumed to be equipped with an SCR system/oxidation catalyst for emissions control and engine cooling is achieved with fin-fan radiators.

3.2 COMMERCIAL STATUS

3.2.1 Simple and Combined Cycle Configurations

CTs and RICE in simple or combined cycle configuration are well proven and commercially available technologies for power generation. The major CT and RICE OEMs have significant experience throughout the world. RICE units generally range in size from 100 kW to 20 MW and current CT offerings range in size from 1.5 MW to 370 MW. A list of some of the most prevalent suppliers for CT and RICE technologies is provided in Table 3.2-1. Numerous HRSG and steam turbine suppliers exist for combined cycle applications, also.

Table 3.2-1. CT and RICE Manufacturers

Turbine OEMs	RICE OEMs
Alstom	Caterpillar
General Electric	Cummins
Hitachi (Mitsubishi)	Fairbanks Morse
Kawasaki	GE Jenbacher
Mitsubishi	GE Waukesha
PW Power Systems (Mitsubishi)	Kawasaki
Rolls-Royce (Siemens)	MAN Turbo & Diesel
Siemens	Mitsubishi
Solar Turbines	Wartsila

3.2.2 Carbon Capture and Sequestration (CCS)

Carbon capture and sequestration (CCS) technology is commercially available for natural gas power plants, but it has been employed on a limited number of facilities and often on a reduced scale or slip stream application in demonstration applications. Generally, CCS technology includes a large capital investment and high operating costs as well as plant performance and operating impacts. As such, implementation of this technology is most economical for larger scale, combined cycle power plants that operate at a fairly high capacity factor and less economical in peaking or intermediate facilities with daily starts and stops. The regulations surrounding long-term sequestration of CO_2 are also not well established.

Natural gas CCS generally consists of two components: the removal or capture of CO_2 from a natural gas power plant exhaust gas stream and the transportation and storage of the CO_2. Carbon capture for natural gas power plants has traditionally considered use of post-combustion capture (PCC) technology. This technology uses a solvent, such as an amine solution, to bind with CO_2 from the exhaust gas. The CO_2 laden solvent is separated from the rest of the exhaust gas and heated, which then separates the bound CO_2 from the solvent. The separated CO_2 is cooled and compressed and can be transported by pipeline to a suitable location for permanent injection into the ground (sequestration) or for enhanced oil recovery (EOR). Figure 3.2-1 depicts a typical CCS process.

Figure 3.2-1. Natural Gas Power Plant CO_2 PCC System with Sequestration[15]

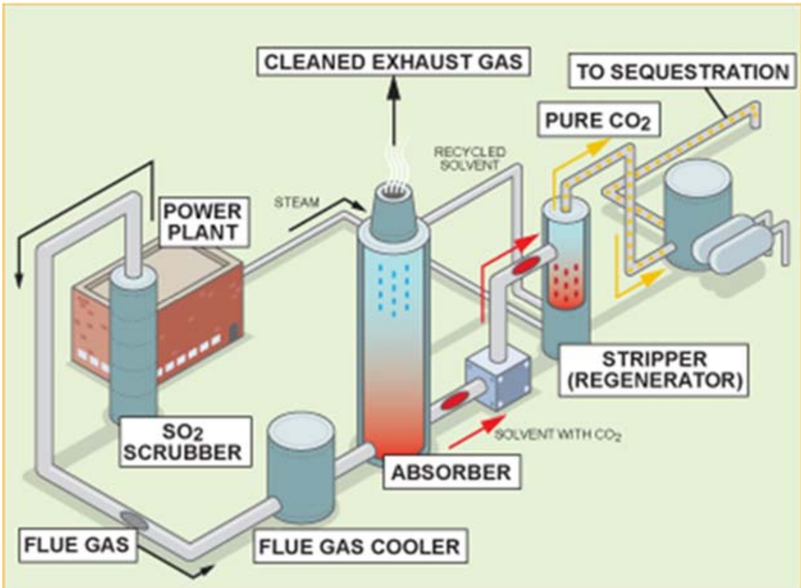

Table 3.2-2 depicts the expected plant capacity, heat rate, and plant capital and operating cost impacts for a natural gas combined cycle power plant. Given the cost and operational impacts of PCC on a gas plant, a large scale combined cycle project has been presented as more industry data is available for this project size, but similar project impacts can be expected for a smaller scale facility.

Table 3.2-2. Estimated CCS Impacts to Conventional Combined Cycle[16]

	Net Output (MW)	Net Heat Rate (Btu/kWh)	Capital Costs ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)
Nominal CCS % Change (Compared to Combined Cycle)	-21%	19%	89%	256%	234%

In actuality, several variations of PCC systems exist and the costs and operating impacts may vary depending on the technology utilized and the final pressure the CO_2 is compressed to. In general, the 30 year levelized cost for capture and compression of the CO_2 is estimated to cost $30 to $70 per ton of CO_2 removed for a combined cycle facility. The cost of sequestration includes CO_2 transportation by pipeline and storage and monitoring, which is typically about ¼ the total cost of capture and sequestration. Typical sequestration costs are estimated to be approximately $8 to $15/ton of CO_2 removed (no EOR) and can vary depending on the distance to transport, the geological formation of the area for storage, and whether any economic benefit results (such as in the case of EOR). Currently, there is no large scale industry supporting sequestration and long term monitoring of carbon. Most sequestration projects have consisted of smaller scale EOR efforts or demonstration sequestration projects.

As an alternative to PCC systems, a technology utilizing oxy fuel firing may also be employed that utilizes a pure oxygen stream, which must be produced from an air

[15] http://www.fossiltransition.org/pages/post_combustion_capture_/128.php
[16] U.S. EIA Cost and Performance Characteristics of New Generating Technologies, Annual Outlook 2018

separation unit, for the combustion process rather than air. This reduces plant emissions and produces an exhaust gas that is composed almost entirely of water and CO_2. The CO_2 is compressed to a supercritical condition and is utilized for power production utilizing the Allam cycle. Somewhat similar to a conventional steam turbine generator, the Allam cycle utilizes a fluid turbine, but with CO_2 as the working fluid. The CO_2 that exhausts from the turbine is re-pressurized for sequestration or EOR. A portion of the exhaust CO_2 is recirculated back to the pure oxygen stream and used in the combustion process. This technology is expected to be more efficient, compact, and cost effective than traditional PCC systems, but currently has only been tested in a demonstration project application. Net Power, a consortium of companies including Exelon and Toshiba, has most recently developed a demonstration project that is nominally 25 MW in size and began operation in 2018. The turbine supplier, Toshiba, has stated that the commercial plant will be larger in scale, consisting of two turbines in the 200 to 300 MW size range. Since the technology has not been widely demonstrated, limited information is currently available regarding plant project costs and operating costs for this technology.

3.3 OPERATIONAL CONSIDERATIONS

3.3.1 Fuel Assumptions

For the thermal generation assets described in this report, natural gas was assumed to be the primary fuel source. Supply line pressures assumed for each of the three sites considered are provided in Table 3.3-1 along with the assumed gas higher heating value (HHV)[17].

Table 3.3-1. Natural Gas Heating Values and Delivery Pressures

NG Characteristics	HHV (btu/lb)	Supply Pressure (PSIG)
Western Montana	22,029	550
Eastern Montana	22,029	550
South Dakota	22,029	600

For the two dual fuel generation assets considered in this study, both LNG and No. 2 distillate fuel oil were considered as backup fuel sources. The assumed characteristics of the LNG and fuel oil are summarized in Table 3.3-2.

Table 3.3-2. Backup Fuel Characteristics

Back-Up Fuel Characteristics	LNG HHV (btu/lb)	FO HHV (btu/lb)
Western Montana	22,029	18,200
Eastern Montana	22,029	18,200
South Dakota	22,029	18,200

[17] Thermal heat rates are presented on an HHV basis in this report, which takes into account the latent heat of vaporization of the water in the combustion products, versus lower heating value (LHV) basis, which does not.

Generation assets capable of operating on backup fuels were assumed to operate on the selected backup fuel for a total of 240 hours during the year for the purpose of estimating O&M costs.

3.3.2 Plant Performance

Overall new and clean net plant outputs and heat rates are summarized for each of the natural gas-fired thermal technologies in Tables 3.3-3 through 3.3-5 and for the dual fuel technologies in Tables 3.3-6 through 3.3-8. Output and thermal degradation over the asset life for the thermal options were accounted for in the dispatch modeling inputs based on supplier degradation curves and typical equipment degradation.

Table 3.3-3. Primary Fuel Estimated Plant Performance – Western Montana

		Summer - 100% Load		Winter Day - 100% Load	
Western Montana	Fuel	Net Output	Net HR (HHV)	Net Output	Net HR (HHV)
Technology	Type	kW	Btu/kWh	kW	Btu/kWh
Simple Cycle 1x0 CT - 50 MW Frame	NG	42,056	10,081	45,822	9,986
Simple Cycle 1x0 CT - 25 MW Aeroderivative	NG	23,603	10,252	26,722	9,902
Simple Cycle 1x0 CT - 50 MW Aeroderivative	NG	43,109	9,614	45,168	9,388
Combined Cycle 2x1 CT - Frame CT	NG	117,530	7,222	126,961	7,210
Combined Cycle 2x1 CT - Frame CT w/ DB (Unfired)	NG	117,674	7,223	126,934	7,221
Combined Cycle 2x1 CT - Frame CT w/ DB (Fired)	NG	133,712	7,533	144,633	7,533
Simple Cycle 1x0 RICE - 18 MW Class	NG	17,932	8,514	18,496	8,329
Simple Cycle 1x0 RICE - 9 MW Class	NG	9,087	8,185	9,173	8,103

Table 3.3-4. Primary Fuel Estimated Plant Performance – Eastern Montana

		Summer - 100% Load		Winter Day - 100% Load	
Eastern Montana	Fuel	Net Output	Net HR (HHV)	Net Output	Net HR (HHV)
Technology	Type	kW	Btu/kWh	kW	Btu/kWh
Simple Cycle 1x0 CT - 50 MW Frame	NG	44,381	10,057	48,938	9,970
Simple Cycle 1x0 CT - 25 MW Aeroderivative	NG	24,858	10,273	29,068	9,921
Simple Cycle 1x0 CT - 50 MW Aeroderivative	NG	45,412	9,604	47,279	9,369
Combined Cycle 2x1 CT - Frame CT	NG	123,423	7,236	133,486	7,213
Combined Cycle 2x1 CT - Frame CT w/ DB (Unfired)	NG	123,431	7,239	133,933	7,192
Combined Cycle 2x1 CT - Frame CT w/ DB (Fired)	NG	139,877	7,560	151,957	7,530
Simple Cycle 1x0 RICE - 18 MW Class	NG	18,495	8,370	18,495	8,318
Simple Cycle 1x0 RICE - 9 MW Class	NG	9,173	8,160	9,173	8,103

Table 3.3-5. Primary Fuel Estimated Plant Performance – South Dakota

		Summer - 100% Load		Winter Day - 100% Load	
South Dakota	Fuel	Net Output	Net HR (HHV)	Net Output	Net HR (HHV)
Technology	Type	kW	Btu/kWh	kW	Btu/kWh
Simple Cycle 1x0 CT - 50 MW Frame	NG	46,963	10,087	53,570	9,941
Simple Cycle 1x0 CT - 25 MW Aeroderivative	NG	26,053	10,350	30,934	9,867
Simple Cycle 1x0 CT - 50 MW Aeroderivative	NG	48,197	9,615	53,514	9,296
Combined Cycle 2x1 CT - Frame CT	NG	131,457	7,208	147,859	7,206
Combined Cycle 2x1 CT - Frame CT w/ DB (Unfired)	NG	131,344	7,216	148,074	9,867
Combined Cycle 2x1 CT - Frame CT w/ DB (Fired)	NG	148,642	7,529	167,871	7,537
Simple Cycle 1x0 RICE - 18 MW Class	NG	18,495	8,409	18,495	8,318
Simple Cycle 1x0 RICE - 9 MW Class	NG	9,173	8,119	9,173	8,103

Table 3.3-6. Backup Fuel Estimated Plant Performance – Western Montana

		Summer - 100% Load		Winter Day - 100% Load	
Western Montana	**Fuel**	**Net Output**	**Net HR (HHV)**	**Net Output**	**Net HR (HHV)**
Technology	**Type**	**kW**	**Btu/kWh**	**kW**	**Btu/kWh**
Simple Cycle 1x0 CT - 50 Aeroderivative	LNG	43,084	9,764	45,143	9,533
Simple Cycle 1x0 CT - 50 Aeroderivative	FO	42,247	9,806	44,264	9,576
Simple Cycle 1x0 RICE (NG Only)	LNG	17,907	8,525	18,471	8,465
Simple Cycle 1x0 RICE (Dual Fuel)	NG	16,498	8,524	17,016	8,463
Simple Cycle 1x0 RICE (Dual Fuel)	FO	14,204	8,721	14,651	8,659

Table 3.3-7. Backup Fuel Estimated Plant Performance – Eastern Montana

		Summer - 100% Load		Winter Day - 100% Load	
Eastern Montana	**Fuel**	**Net Output**	**Net HR (HHV)**	**Net Output**	**Net HR (HHV)**
Technology	**Type**	**kW**	**Btu/kWh**	**kW**	**Btu/kWh**
Simple Cycle 1x0 CT - 50 Aeroderivative	LNG	45,387	9,754	47,254	9,515
Simple Cycle 1x0 CT - 50 Aeroderivative	FO	44,504	9,797	46,333	9,556
Simple Cycle 1x0 RICE (NG Only)	LNG	18,470	8,506	18,470	8,454
Simple Cycle 1x0 RICE (Dual Fuel)	NG	17,015	8,505	17,015	8,453
Simple Cycle 1x0 RICE (Dual Fuel)	FO	14,650	8,702	14,650	8,648

Table 3.3-8. Backup Fuel Estimated Plant Performance – South Dakota

		Summer - 100% Load		Winter Day - 100% Load	
South Dakota	**Fuel**	**Net Output**	**Net HR (HHV)**	**Net Output**	**Net HR (HHV)**
Technology	**Type**	**kW**	**Btu/kWh**	**kW**	**Btu/kWh**
Simple Cycle 1x0 CT - 50 Aeroderivative	LNG	48,172	9,764	53,489	9,440
Simple Cycle 1x0 CT - 50 Aeroderivative	FO	47,233	9,807	52,443	9,482
Simple Cycle 1x0 RICE (NG Only)	LNG	18,470	8,554	18,470	8,454
Simple Cycle 1x0 RICE (Dual Fuel)	NG	17,015	8,553	17,015	8,453
Simple Cycle 1x0 RICE (Dual Fuel)	FO	14,650	8,751	14,650	8,648

3.3.3 Staffing Requirements

Typical staffing levels for a simple cycle configuration are minimal and, for the purposes of this analysis, include one salaried and two hourly staff. For a combined cycle configuration, staffing levels are typically greater as compared to a simple cycle configuration: six salaried and 18 hourly staff were assumed for the combined cycle configurations.

3.3.4 Environmental Considerations

3.3.4.1 Emissions

Plant emission rates and air quality control equipment assumed for each natural gas generation option are those typically expected to be achievable and permittable based on the fuels used and the specific generation technology. Emissions rates were estimated and are provided on a lb/MWh basis.

Air emissions estimates for the various options are presented in Tables 3.3-9 and 3.3-10 for the natural gas only and dual fuel configurations, respectively. These are based on limits which would be expected for air permit approval for a project located in Montana.

Table 3.3-9. Estimated Primary Fuel Emission Rates[18]

Estimated Air Emissions	Fuel	Heat Input	Net Output	NOx	PM10	SO2	CO	CO2
Technology	Type	mmBtu/hr	MW	lb/MWh	lb/MWh	lb/MWh	lb/MWh	lb/MWh
Simple Cycle 1x0 CT - 50 MW Frame/Industrial	NG	474	47.0	0.082	0.06	0.0141	0.06	1,190
Simple Cycle 1x0 CT - 25 MW Aeroderivative	NG	270	26.1	0.084	0.059	0.014	0.064	1,221
Simple Cycle 1x0 CT - 50 MW Aeroderivative	NG	463	48.2	0.078	0.055	0.013	0.060	1,135
Combined Cycle 2x1 CT - Frame CT	NG	948	131.5	0.058	0.041	0.010	0.045	851
Combined Cycle 2x1 CT - Frame CT w/ DB (Unfired)	NG	948	131.3	0.058	0.041	0.010	0.045	852
Combined Cycle 2x1 CT - Frame CT w/ DB (Fired)	NG	1,119	148.6	0.061	0.043	0.011	0.047	888
Simple Cycle 1x0 RICE - 18 MW Class	NG	156	18.5	0.153	0.048	0.012	0.311	992
Simple Cycle 1x0 RICE - 9 MW Class	NG	74	9.2	0.151	0.046	0.011	0.280	958

Table 3.3-10. Estimated Backup Fuel Emission Rates

Estimated Air Emissions	Fuel	Heat Input	Net Output	NOx	PM10	SO2	CO	CO2
Technology	Type	mmBtu/hr	MW	lb/MWh	lb/MWh	lb/MWh	lb/MWh	lb/MWh
Simple Cycle 1x0 CT - 50 MW Aeroderivative	LNG	471	48.2	0.079	0.055	0.014	0.061	1,152
Simple Cycle 1x0 CT - 50 MW Aeroderivative	FO	503	51.3	0.199	0.056	0.081	0.145	1,569
Simple Cycle 1x0 RICE - 18 MW Class (NG Only)	LNG	156	18.5	0.153	0.048	0.012	0.311	992
Simple Cycle 1x0 RICE - 18 MW Class (Dual Fuel)	NG	145	17.0	0.215	0.049	0.017	0.316	1,045
Simple Cycle 1x0 RICE - 18 MW Class (Dual Fuel)	FO	128	14.6	1.240	0.050	0.072	0.431	1,399

3.3.4.2 Water Supply/Wastewater Discharge

For the thermal technologies, water consumption rates are estimated based on a rough conceptual design of the resource option and assume a blow down discharge stream to a nearby water body or municipal sewer system. The rates also assume the utilization of inlet air evaporative cooling on summer day conditions for the CT alternatives. For applicable systems, an ACC heat rejection system has been utilized. Tables 3.3-11 through 3.3-13 summarize the estimated water consumption and wastewater discharge for each technology option. These rates are based upon the assumption that the facility design incorporates recycling and reusing water to the greatest extent possible.

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[18] The New Source Performance Standard (NSPS) for CO_2 is 1,000 lb/MWh. Based on this limit and the US EPA guidelines for determining associated operating limits, the simple cycle CTs would be limited to nominally 3,000 hours of operation per year.

Table 3.3-11. Water Consumption / Wastewater Discharge – Western Montana

	Summer Day		Average Day	
Western Montana	**Consumption**	**Discharge**	**Consumption**	**Discharge**
Technology	**gal / MWh**	**gal / MWh**	**gal / MWh**	**gal / MWh**
Simple Cycle 1x0 CT - 50 MW Frame	19.90	1.07	2.04	2.04
Simple Cycle 1x0 CT - 25 MW Aeroderivative	24.10	1.91	3.47	3.47
Simple Cycle 1x0 CT - 50 MW Aeroderivative	45.54	1.04	2.11	2.11
Combined Cycle 2x1 CT - Frame CT	14.96	0.38	2.15	0.73
Combined Cycle 2x1 CT - Frame CT w/ DB (Unfired)	14.75	0.38	1.97	0.73
Combined Cycle 2x1 CT - Frame CT w/ DB (Fired)	13.61	0.34	2.35	0.64
Simple Cycle 1x0 RICE - 18 MW Class	5.02	2.51	4.90	4.90
Simple Cycle 1x0 RICE - 9 MW Class	9.90	4.95	9.89	9.89

Table 3.3-12. Water Consumption / Wastewater Discharge – Eastern Montana

	Summer Day		Average Day	
Eastern Montana	**Consumption**	**Discharge**	**Consumption**	**Discharge**
Technology	**gal / MWh**	**gal / MWh**	**gal / MWh**	**gal / MWh**
Simple Cycle 1x0 CT - 50 MW Frame	20.98	1.01	1.93	1.93
Simple Cycle 1x0 CT - 25 MW Aeroderivative	24.92	1.81	3.34	3.34
Simple Cycle 1x0 CT - 50 MW Aeroderivative	46.63	0.99	26.18	1.88
Combined Cycle 2x1 CT - Frame CT	15.57	0.36	2.12	0.69
Combined Cycle 2x1 CT - Frame CT w/ DB (Unfired)	15.39	0.36	1.95	0.69
Combined Cycle 2x1 CT - Frame CT w/ DB (Fired)	14.21	0.32	2.33	0.61
Simple Cycle 1x0 RICE - 18 MW Class	4.87	2.43	4.87	4.87
Simple Cycle 1x0 RICE - 9 MW Class	9.81	4.91	9.81	9.81

Table 3.3-13. Water Consumption / Wastewater Discharge – South Dakota

	Summer Day		Average Day	
South Dakota	**Consumption**	**Discharge**	**Consumption**	**Discharge**
Technology	**gal / MWh**	**gal / MWh**	**gal / MWh**	**gal / MWh**
Simple Cycle 1x0 CT - 50 MW Frame	14.19	0.96	1.77	1.77
Simple Cycle 1x0 CT - 25 MW Aeroderivative	17.11	1.73	3.04	3.04
Simple Cycle 1x0 CT - 50 MW Aeroderivative	40.10	0.93	25.76	1.72
Combined Cycle 2x1 CT - Frame CT	10.64	0.34	2.05	0.64
Combined Cycle 2x1 CT - Frame CT w/ DB (Unfired)	10.47	0.34	1.90	0.64
Combined Cycle 2x1 CT - Frame CT w/ DB (Fired)	9.87	0.30	2.28	0.56
Simple Cycle 1x0 RICE - 18 MW Class	4.87	2.43	4.87	4.87
Simple Cycle 1x0 RICE - 9 MW Class	9.81	4.91	9.81	9.81

3.4 CONCEPTUAL CAPITAL COST ESTIMATES

Tables 3.4-1 through 3.4-3 summarize the conceptual capital EPC cost estimates for each of the natural gas thermal options considered and Tables 3.4-4 through 3.4-6 summarize the conceptual capital EPC cost estimates for the dual fuel options considered. Project cost estimate summary sheets for the thermal options are included in Appendix A and cost estimating basis is summarized in Section 2.5[19].

Table 3.4-1. Conceptual Capital Costs (Single Fuel) – Western Montana

Western Montana - Single Fuel	Winter Output	Conceptual Capital Cost	
Technology	**kW**	**$1,000**	**$/kW**
Simple Cycle 1x0 CT - 50 MW Frame	45,822	$ 65,672	$ 1,433
Simple Cycle 1x0 CT - 25 MW Aeroderivative	26,722	$ 44,339	$ 1,659
Simple Cycle 1x0 CT - 50 MW Aeroderivative	45,168	$ 60,337	$ 1,336
Combined Cycle 2x1 CT - Frame CT	126,961	$ 168,025	$ 1,323
Combined Cycle 2x1 CT - Frame CT w/ DB (Fired)	144,633	$ 175,763	$ 1,215
Simple Cycle 1x0 RICE - 18 MW Class	18,496	$ 33,896	$ 1,833
Simple Cycle 1x0 RICE - 9 MW Class	9,102	$ 21,157	$ 2,324

Table 3.4-2. Conceptual Capital Costs (Single Fuel) – Eastern Montana

Eastern Montana - Single Fuel	Winter Output	Conceptual Capital Cost	
Technology	**kW**	**$1,000**	**$/kW**
Simple Cycle 1x0 CT - 50 MW Frame	48,247	$ 65,672	$ 1,361
Simple Cycle 1x0 CT - 25 MW Aeroderivative	28,670	$ 44,339	$ 1,547
Simple Cycle 1x0 CT - 50 MW Aeroderivative	47,279	$ 60,337	$ 1,276
Combined Cycle 2x1 CT - Frame CT	133,486	$ 168,121	$ 1,259
Combined Cycle 2x1 CT - Frame CT w/ DB (Fired)	151,957	$ 175,763	$ 1,157
Simple Cycle 1x0 RICE - 18 MW Class	18,495	$ 33,896	$ 1,833
Simple Cycle 1x0 RICE - 9 MW Class	9,173	$ 21,157	$ 2,306

Table 3.4-3. Conceptual Capital Costs (Single Fuel) – South Dakota

South Dakota - Single Fuel	Summer Output	Conceptual Capital Cost	
Technology	**kW**	**$1,000**	**$/kW**
Simple Cycle 1x0 CT - 50 MW Frame	46,963	$ 65,672	$ 1,398
Simple Cycle 1x0 CT - 25 MW Aeroderivative	26,053	$ 44,339	$ 1,702
Simple Cycle 1x0 CT - 50 MW Aeroderivative	48,197	$ 60,337	$ 1,252
Combined Cycle 2x1 CT - Frame CT	131,344	$ 168,121	$ 1,280
Combined Cycle 2x1 CT - Frame CT w/ DB (Fired)	148,642	$ 175,763	$ 1,182
Simple Cycle 1x0 RICE - 18 MW Class	18,495	$ 33,896	$ 1,833
Simple Cycle 1x0 RICE - 9 MW Class	9,173	$ 9,173	$ 2,306

[19] For the simple cycle aeroderivative and RICE options, the SCR system and oxidation catalyst costs are carried in the prime mover (CT) scope of supply. For the combined cycle options, the SCR system and oxidation catalysts costs are carried in the HRSG scope of supply. For the simple cycle frame CT, associated costs are included as a standalone line item. This is reflected in the conceptual capital cost estimate summary sheets included in Appendix A.

Table 3.4-4. Conceptual Capital Costs (Dual Fuel) – Western Montana

Western Montana - Dual Fuel	Winter Output	Conceptual Capital Cost	
Technology	**kW**	**$1,000**	**$/kW**
Simple Cycle 1x0 CT - 50 MW Aeroderivative (LNG)	45,143	$ 81,571	$ 1,807
Simple Cycle 1x0 CT - 50 MW Aeroderivative (FO)	44,264	$ 67,080	$ 1,515
Simple Cycle 1x0 RICE - 18 MW Class NG Only (LNG)	18,470	$ 39,723	$ 2,151
Simple Cycle 1x0 RICE - 18 MW Class Dual Fuel (FO)	17,016	$ 34,312	$ 2,016

Table 3.4-5. Conceptual Capital Costs (Dual Fuel) – Eastern Montana

Eastern Montana - Dual Fuel	Winter Output	Conceptual Capital Cost	
Technology	**kW**	**$1,000**	**$/kW**
Simple Cycle 1x0 CT - 50 MW Aeroderivative (LNG)	47,254	$ 81,571	$ 1,726
Simple Cycle 1x0 CT - 50 MW Aeroderivative (FO)	46,333	$ 67,080	$ 1,448
Simple Cycle 1x0 RICE - 18 MW Class NG Only (LNG)	18,470	$ 39,723	$ 2,151
Simple Cycle 1x0 RICE - 18 MW Class Dual Fuel (FO)	17,015	$ 34,312	$ 2,017

Table 3.4-6. Conceptual Capital Costs (Dual Fuel) – South Dakota

South Dakota - Dual Fuel	Summer Output	Conceptual Capital Cost	
Technology	**kW**	**$1,000**	**$/kW**
Simple Cycle 1x0 CT - 50 MW Aeroderivative (LNG)	48,172	$ 81,571	$ 1,693
Simple Cycle 1x0 CT - 50 MW Aeroderivative (FO)	47,233	$ 67,080	$ 1,420
Simple Cycle 1x0 RICE - 18 MW Class NG Only (LNG)	18,470	$ 39,723	$ 2,151
Simple Cycle 1x0 RICE - 18 MW Class Dual Fuel (FO)	17,015	$ 34,312	$ 2,017

3.5 CONCEPTUAL O&M COSTS

Estimated O&M costs for the thermal generation options (natural gas only) are summarized in Tables 3.5-1 through 3.5-3[20]. Estimated O&M costs include fixed and variable O&M costs associated with operating and maintaining the facility and consider costs associated with long term service agreements for major equipment.

Simple cycle CT and RICE options assumed a peaking dispatch profile with a nominal 15% capacity factor (1,292 hours of operation annually). The combined cycle options assumed an intermediate load dispatch profile with a nominal 47% capacity factor (4,136 hours of operation annually).

[20] Only one total annual O&M build-up was created for each of the options considered. The variation in the $/kW-yr and $/MWh values between the different sites is due to differences in estimated performance at the different site conditions.

Table 3.5-1. Conceptual O&M Costs – Western Montana

Western Montana	Fixed O&M	Variable O&M
Technology - Natural Gas	**$/kW-yr**	**$/MWh**
Simple Cycle 1x0 CT - 50 MW Frame	$ 13.18	$ 8.73
Simple Cycle 1x0 CT - 25 MW Aeroderivative	$ 20.42	$ 5.58
Simple Cycle 1x0 CT - 50 MW Aeroderivative	$ 13.38	$ 4.38
Combined Cycle 2x1 CT - Frame CT	$ 25.75	$ 6.30
Combined Cycle 2x1 CT - Frame CT w/ DB (Unfired)	$ 25.85	$ 6.31
Combined Cycle 2x1 CT - Frame CT w/ DB (Fired)	$ 22.69	$ 5.55
Simple Cycle 1x0 RICE - 18 MW Class	$ 23.26	$ 4.68
Simple Cycle 1x0 RICE - 9 MW Class	$ 54.62	$ 4.55

Table 3.5-2. Conceptual O&M Costs – Eastern Montana

Eastern Montana	Fixed O&M	Variable O&M
Technology - Natural Gas	**$/kW-yr**	**$/MWh**
Simple Cycle 1x0 CT - 50 MW Frame	$ 12.52	$ 8.30
Simple Cycle 1x0 CT - 25 MW Aeroderivative	$ 19.03	$ 5.37
Simple Cycle 1x0 CT - 50 MW Aeroderivative	$ 12.78	$ 4.05
Combined Cycle 2x1 CT - Frame CT	$ 24.49	$ 5.99
Combined Cycle 2x1 CT - Frame CT w/ DB (Unfired)	$ 24.50	$ 6.00
Combined Cycle 2x1 CT - Frame CT w/ DB (Fired)	$ 21.60	$ 5.31
Simple Cycle 1x0 RICE - 18 MW Class	$ 23.07	$ 4.64
Simple Cycle 1x0 RICE - 9 MW Class	$ 54.20	$ 4.52

Table 3.5-3. Conceptual O&M Costs – South Dakota

South Dakota	Fixed O&M	Variable O&M
Technology - Natural Gas	**$/kW-yr**	**$/MWh**
Simple Cycle 1x0 CT - 50 MW Frame	$ 12.93	$ 7.62
Simple Cycle 1x0 CT - 25 MW Aeroderivative	$ 20.94	$ 4.91
Simple Cycle 1x0 CT - 50 MW Aeroderivative	$ 12.54	$ 3.72
Combined Cycle 2x1 CT - Frame CT	$ 24.87	$ 5.99
Combined Cycle 2x1 CT - Frame CT w/ DB (Unfired)	$ 24.99	$ 5.51
Combined Cycle 2x1 CT - Frame CT w/ DB (Fired)	$ 22.08	$ 4.88
Simple Cycle 1x0 RICE - 18 MW Class	$ 23.07	$ 4.65
Simple Cycle 1x0 RICE - 9 MW Class	$ 54.20	$ 4.57

Dual fuel estimated fixed and variable O&M costs are summarized in Table 3.5-4 through 3.5-6. These costs represent the fixed and variable O&M costs for operation on the respective alternate fuel[21]. An operational profile of 240 hours annually of facility operation on the secondary fuel was assumed in developing these costs.

[21] Except for the dual fuel (NG/FO) RICE technology, the fixed costs are only incremental fixed costs that are incurred if a dual fuel plant is utilized. As such, these costs do not include plant staffing and other costs that would already be incurred at the facility.

Table 3.5-4. Conceptual Dual Fuel O&M Costs – Western Montana

Western Montana	Fixed O&M	Variable O&M
Technology - Dual Fuel	$/kW-yr	$/MWh
Simple Cycle 1x0 CT - 50 MW Aeroderivative (LNG)	$ 13.88	$ 6.12
Simple Cycle 1x0 CT - 50 MW Aeroderivative (FO)	$ 13.81	$ 8.11
Simple Cycle 1x0 RICE - 18 MW Class NG Only (LNG)	$ 23.62	$ 6.35
Simple Cycle 1x0 RICE - 18 MW Class Dual Fuel (NG)	$ 25.31	$ 5.77
Simple Cycle 1x0 RICE - 18 MW Class Dual Fuel (FO)	$ 29.70	$ 10.20

Table 3.5-5. Conceptual Dual Fuel O&M Costs – Eastern Montana

Eastern Montana	Fixed O&M	Variable O&M
Technology - Dual Fuel	$/kW-yr	$/MWh
Simple Cycle 1x0 CT - 50 MW Aeroderivative (LNG)	$ 13.26	$ 5.69
Simple Cycle 1x0 CT - 50 MW Aeroderivative (FO)	$ 13.19	$ 7.39
Simple Cycle 1x0 RICE - 18 MW Class NG Only (LNG)	$ 23.43	$ 6.35
Simple Cycle 1x0 RICE - 18 MW Class Dual Fuel (NG)	$ 25.10	$ 5.73
Simple Cycle 1x0 RICE - 18 MW Class Dual Fuel (FO)	$ 29.45	$ 10.20

Table 3.5-6. Conceptual Dual Fuel O&M Costs – South Dakota

South Dakota	Fixed O&M	Variable O&M
Technology - Dual Fuel	$/kW-yr	$/MWh
Simple Cycle 1x0 CT - 50 MW Aeroderivative (LNG)	$ 13.01	$ 5.36
Simple Cycle 1x0 CT - 50 MW Aeroderivative (FO)	$ 12.95	$ 6.71
Simple Cycle 1x0 RICE - 18 MW Class NG Only (LNG)	$ 23.43	$ 4.99
Simple Cycle 1x0 RICE - 18 MW Class Dual Fuel (NG)	$ 25.10	$ 5.73
Simple Cycle 1x0 RICE - 18 MW Class Dual Fuel (FO)	$ 29.45	$ 10.20

3.6 PROJECT IMPLEMENTATION SCHEDULE

Estimated project implementation schedules were developed for each of the thermal generation options based on current day contracting approaches and methodologies and are included in Appendix B. From contractor NTP to COD, the durations for simple cycle CT, simple cycle RICE, and combined cycle configurations are anticipated to be in the range of 22 months, 18 months, and 36 months, respectively.

4.0 WIND TECHNOLOGY

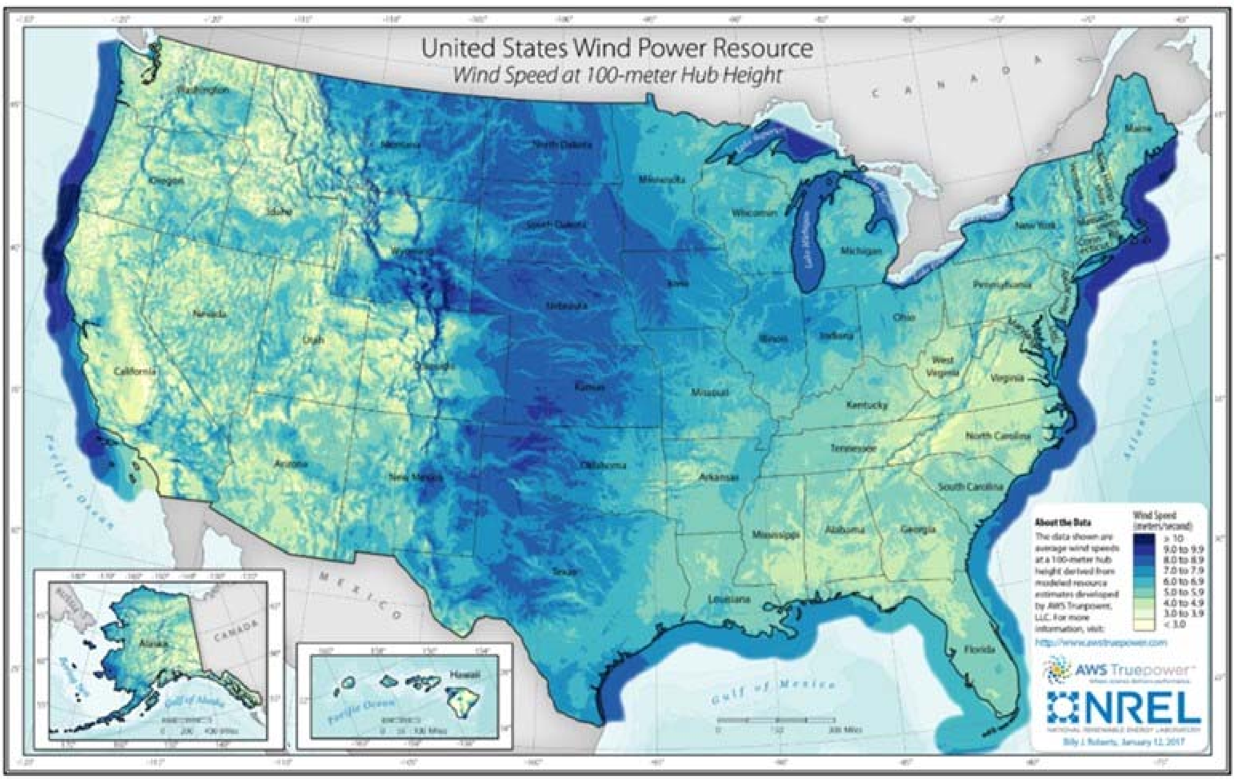
For the purpose of this evaluation, a 100 MW wind generation facility was evaluated as a representative, proxy project size for assessing technology viability in various regions of both Montana and South Dakota.

4.1 TECHNOLOGY OVERVIEW

Wind power is generated by converting the kinetic energy of wind into electricity by rotating a propeller connected to an electrical generator. Wind is an intermittent resource and, as such, wind power is not dispatchable.

A map of wind speeds in the U.S. is shown below in Figure 4.1-1.

Figure 4.1-1. U.S. Wind Speeds at 100m Hub Height



A wind turbine would ideally be located where wind flow is non-turbulent and constant year round without excessive or extreme gusts. Wind speed typically increases with altitude and is higher over open areas without windbreaks such as trees or buildings. Wind data is typically collected for a year or more via meteorological towers to determine general viability of a site.

Adequate spacing between the wind turbines must be maintained to reduce wind energy loss from interferences from nearby turbines. To minimize efficiency losses, wind turbines are commonly spaced three to five rotor diameters apart along an axis that is perpendicular to the prevailing wind direction and five to ten rotor diameters apart along an axis that is parallel to the prevailing wind direction.

4.2 COMMERCIAL STATUS AND CURRENT MARKET

Wind power technology has been adapted and implemented globally. Advances in wind turbine designs have improved plant efficiencies compared to previous designs, allowing wind turbines to be economically implemented in lower class wind power regions.

4.2.1 Current Market Influences

The Federal Production Tax Credit (PTC) has been instrumental in supporting the deployment and growth of wind energy in the U.S.[22] The current tax credit is $0.014/kWh over a 10-year time period for wind facilities commencing construction in 2018. PTCs are being phased out and this tax credit value represents a 40% reduction from the $0.024/kWh base credit originally available under this program. For wind facilities commencing construction in 2019, the tax credit amount is reduced by 60% from the base credit. The tax credit is not available for projects commencing construction after 2019. The phase out of the PTC is summarized in the Table below.

Table 4.2-1. Federal PTC Phase Out Summary for Wind[23,24]

Federal PTC Phase Out					
Year Construction Begins	2016	2017	2018	2019	Future
Wind PTC ($/kWh)	$0.024	$0.019	$0.014	$0.010	-

4.3 OPERATIONAL CONSIDERATIONS

Wind farms are typically designed for a 20 year life, but well maintained turbines can last up to 25 years depending on the service conditions at the site and historical maintenance practices. Typical wind turbine sizes range from nominally 1.5 MW to 5 MW. For this analysis, each turbine was assumed to have a rated power of approximately 2.5 MW and a hub height of 100 meters (m).

Wind turbine capacity is based largely on the length of the propeller blades. Taller turbines are not only able to use longer blades for higher output capacity, but are also able to take advantage of the better wind speeds available at greater heights (while also considering related aviation regulations and requirements).

Due to the maturity and long operating history of wind power technologies, there are few technical performance risks or unknown factors involved in utilizing this technology. Ongoing gearbox and generator design improvements have enhanced the reliability of the equipment.

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[22] Large wind applications are also eligible for the Federal Investment Tax Credit (ITC) if placed into service prior to the end of 2019. However, most utility-scale wind applications pursue the Federal PTC in lieu of the Federal ITC based on benefits realized.
[23] https://www.energy.gov/savings/renewable-electricity-production-tax-credit-ptc
[24] The exact value of the Federal PTC in a given year depends on the inflation adjustment factor used by the Internal Revenue Service (IRS).

4.3.1 Performance Data

For this evaluation, proxy wind farm locations were selected in Montana and South Dakota as shown in Figures 4.3-1 and 4.3-2[25].

Figure 4.3-1. 100 MW Proxy Wind Farm Sites in Montana

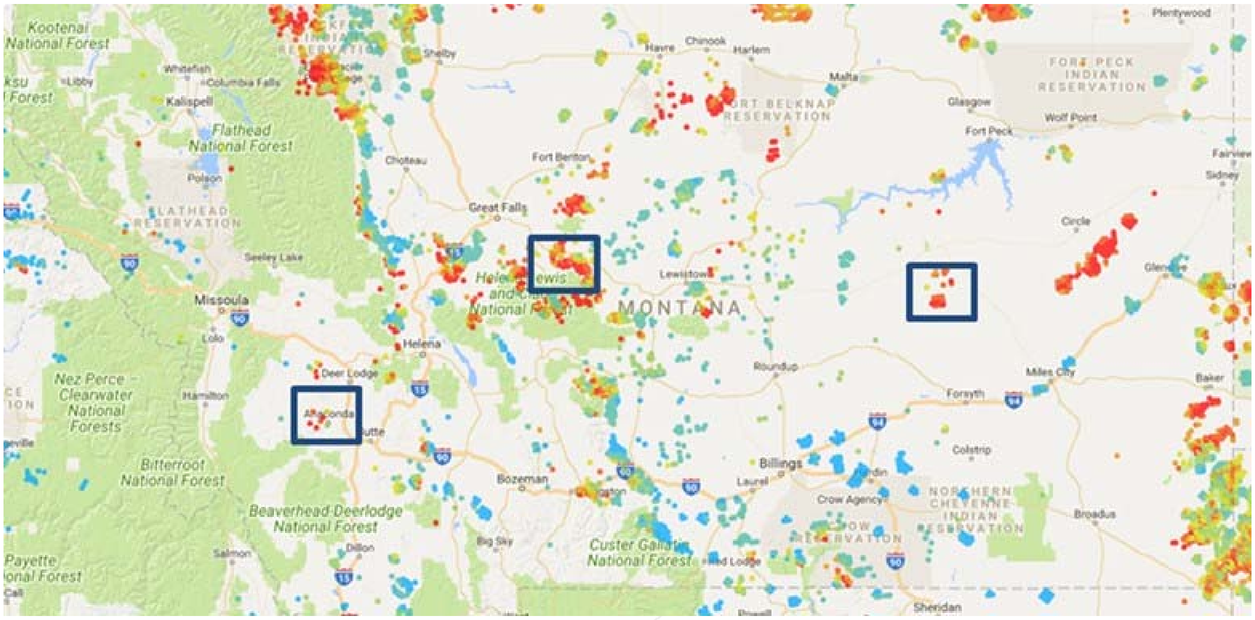
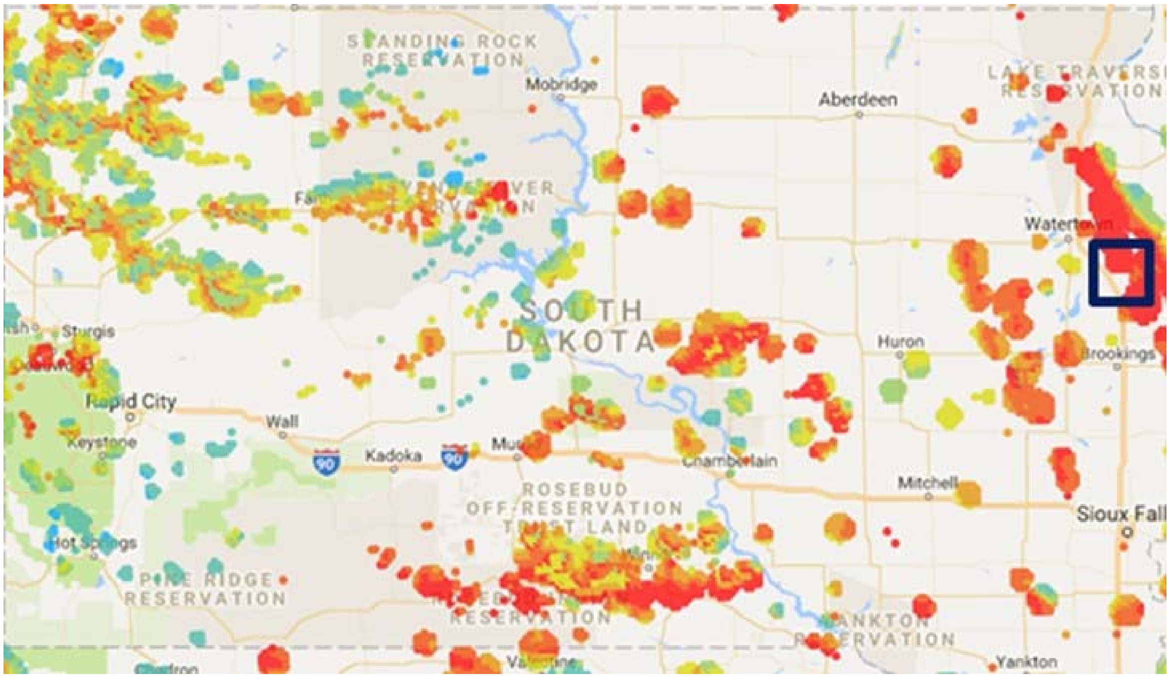


Figure 4.3-2. 100 MW Proxy Wind Farm Sites in South Dakota



[25] The areas of the maps colored in red are locations with the highest relative capacity factors, while those colored in blue and green have the lowest capacity factors.

An average net capacity factor (NCF) range for a wind power facility is typically in the range of 25 to 50 percent depending on available wind energy within the region. The estimated capacity factors for each of the selected sites are shown below in Table 4.3-1.

Table 4.3-1. Wind Turbine Site Estimated NCFs

Wind Site Annual NCFs		
Western Montana	%	41.13%
Eastern Montana	%	44.35%
Central Montana	%	44.38%
South Dakota	%	44.42%

Wind resource data was utilized from the NREL WIND Toolkit application. The WIND Toolkit application includes meteorological conditions and turbine power for over 120,000 sites in the United States. The power data available through this program was developed using wind data at a 100 m hub height and site-appropriate turbine power curves to estimate the power produced at each of the turbine sites. The WIND Toolkit application was created through collaborative efforts between NREL and 3TIER by Vaisala.

4.3.2 Plant Staffing

Staffing for a proposed 100 MW wind power plant generally assumes the utilization of a remote monitoring/operating system. Typical staffing requirements are minimal and for the purpose of this analysis, include one salaried and two hourly staff.

4.4 CONCEPTUAL CAPITAL COST ESTIMATE

The project cost for a 100 MW, 40 turbine wind farm project located in Montana is estimated at $1,410/kW and is estimated at $1,407/kW for South Dakota. This conceptual EPC cost includes the wind turbines, foundations, electrical systems up to the high side of the facility GSU transformers, and instrumentation and controls. The turbines are assumed to be installed on land not owned by NorthWestern resulting in an assumed land lease cost, which is not included in the capital costs (typically included in O&M costs).

4.5 CONCEPTUAL O&M COSTS

Fixed O&M costs for wind farms include staffing and major turbine parts and maintenance costs, including replacement parts and outsourced labor to perform major maintenance.

First year fixed O&M costs for a proxy 100 MW wind power plant are estimated at $37.00/kW-yr. There are typically no reported variable O&M costs associated with wind power generation as they are typically incorporated into the fixed O&M costs on a contractual basis.

4.6 PROJECT IMPLEMENTATION SCHEDULE

Currently, wind power plants have a timeline of nominally two years from contractor NTP through COD. A project implementation schedule is included in Appendix B. Note that all site acquisition and project permitting activities are assumed to be completed prior to contractor NTP.

5.0 SOLAR PHOTOVALTAIC (PV) TECHNOLOGY

For the purpose of this study, a proxy 100 MW solar plant was analyzed in various regions of both Montana and South Dakota.

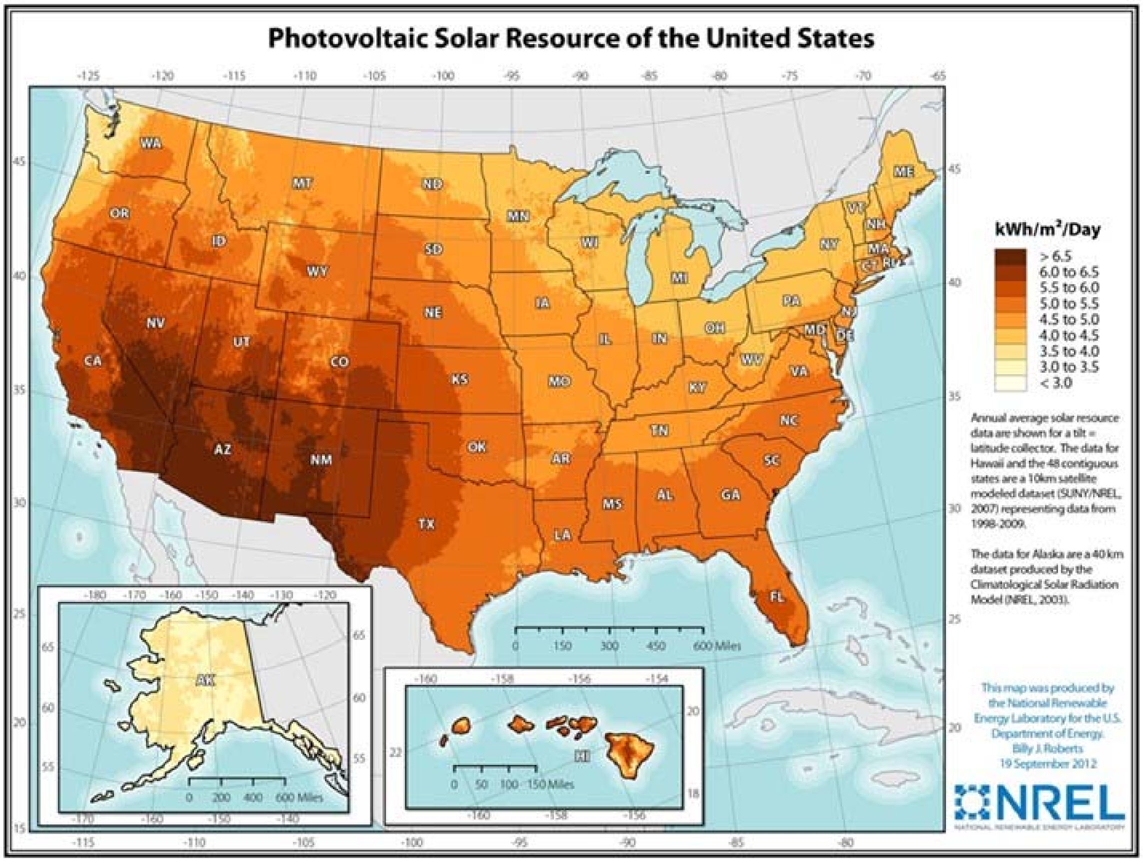
5.1 TECHNOLOGY OVERVIEW

Solar PV technology uses solar cells or photovoltaic arrays to convert light from the sun directly into electricity. PV cells are made of different semiconductor materials and come in many sizes, shapes, and ratings. Solar cells produce direct current (DC) electricity and therefore require a DC to alternating current (AC) converter to allow for grid connected installations.

The PV arrays are mounted on structures that can either tilt the PV array at a fixed angle or incorporate tracking mechanisms that automatically move the panels to follow the sun across the sky. The fixed angle is determined by the local latitude, orientation of the structure, and electrical load requirements. Tracking systems provide more energy production. Single-axis trackers are designed to track the sun from east to west and dual-axis trackers allow for modules to remain pointed directly at the sun throughout the day. This evaluation considers a single-axis tracking configuration.

The amount of electricity produced from PV cells depends on the quantity and quality of light available and performance characteristics of the PV cell. The largest PV systems in the country are located in the Southwestern regions where, as shown in Figure 5.1-1, the strongest solar resources are available.

Figure 5.1-1. U.S. Photovoltaic Solar Resource



5.2 COMMERCIAL STATUS AND CURRENT MARKET

PV cells are a commercially available, mature technology with a significant installed operating base.

5.2.1 Current Market Influences

The Federal Investment Tax Credit (ITC) has been instrumental in supporting the deployment and growth of solar energy in the U.S. The ITC currently offers a 30% tax credit towards the investment cost of solar systems. For a solar project to get the 30% ITC, it must begin construction by December 31, 2019, but it does not have to go into service until December 31, 2023. The percentage steps down to 26% and 22% for projects that start construction in 2020 in 2021, respectively. For all scenarios where a solar project receives greater than a 10% ITC, the project must be placed into service by December 31, 2023. A summary of the Federal ITC phase down is provided in the Table below.

Table 5.2-1. Federal ITC Phase Down for Solar PV[26]

Federal ITC Phase Down								
Year Construction Begins	2016	2017	2018	2019	2020	2021	2022	Future
Solar ITC	30%	30%	30%	30%	26%	22%	10%	10%

Recently, the U.S. imposed a 30% tariff on imported crystalline-silicon solar cells and modules that went into effect February 7, 2018. The tariffs start at 30% of the cell price in 2018 and then gradually drop to 15% by February 7, 2021. Per SEIA, the 30% tariff can be expected to increase year 1 PV module prices by roughly $0.10/W or $100/kW.

5.3 OPERATIONAL CONSIDERATIONS

A 100 MW single-axis tracking PV installation was considered for this evaluation. This installation would include approximately 40, 2.5 MW arrays each consisting of about 8,764 modules of 370 Wp capacity. The land area required for this application would be extensive depending on a variety of factors including the land and design, but could roughly require 400 to 700 acres of land to support the capacity.

The major components included in the PV system include the PV modules/arrays, DC to AC converters/inverters, and mounting structures.

5.3.1 Performance Data

Proxy 100 MW solar facility sites were selected in western Montana, eastern Montana, and South Dakota. An average capacity factor range for a solar power facility is typically in the range of 10 to 30 percent, with annual averages around 25 percent depending upon solar resource within the region. The estimated annual average capacity factors for each of the general site locations are shown below in Table 5.3-1.

Table 5.3-1. Estimated Solar Site NCFs

Solar PV Site Annual NCFs		
Western Montana	%	24.20%
Eastern Montana	%	24.50%
South Dakota	%	24.10%

The capacity factors were estimated using NREL's PVSyst program.

5.3.2 Staffing Requirements

Staffing for a 100 MW solar PV installation generally assumes the utilization of a remote monitoring/operating system. The majority of the staff is typically required for maintenance and panel cleaning. Typical staffing requirements are minimal and, for the purpose of this analysis, include one salaried and two hourly staff.

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[26] https://www.energy.gov/savings/business-energy-investment-tax-credit-itc

5.4 CONCEPTUAL CAPITAL COST ESTIMATE

The project cost for a solar plant located in either Montana or South Dakota is estimated at nominally $1,330/kW prior to implementation of the tariff. Based upon the estimated impact of solar tariffs identified by SEIA, costs could be expected to increase as a result of the tariff to $1,430/kW. The estimated solar project cost includes the modules, structures, inverters, the balance of the system, and engineering and management services (refer to Section 2.5 for general cost basis).

5.5 CONCEPTUAL O&M COSTS

First year fixed O&M costs for a 100 MW solar power plant are estimated to be $21.60/kW-yr. There are typically no variable O&M costs associated with solar power generation.

5.6 PROJECT IMPLEMENTATION SCHEDULE

Currently, solar PV installations have a timeline of approximately 1 to 2 years from EPC NTP through COD. A conceptual project implementation schedule is included in Appendix B.

6.0 GEOTHERMAL TECHNOLOGY

Geothermal power is similar to other steam turbine power stations in that a heating source is used to heat water or another working fluid. The working fluid is then used to turn a turbine. For geothermal power the heat is derived from the thermal energy stored in the earth's crust. High temperature thermal reservoirs are the most beneficial for utility-scale electricity production, but are geologically limited to locations where geothermal pressure reserves are found. For the purpose of this study, a 20 MW geothermal flash plant was assumed within NorthWestern's territory.

6.1 TECHNOLOGY OVERVIEW

Geothermal energy consists of the thermal energy stored in the earth's crust. Reservoirs of geothermal energy are generally classified as being either low temperature (<300°F) or high temperature (>300°F). See Figures 6.1-1 and 6.1-2 for geothermal maps that estimate the temperatures available at both 3 km and 6 km depths, respectively.

Currently, three types of geothermal power plants are commercially developed: dry steam, flash steam, and the binary cycle. On a global basis, flash technology composes approximately 60 percent of the installed capacity, whereas 25 percent of the installed capacity is dry steam. Binary cycle plant technology is utilized in the remaining plants.

The flash steam technology has been assumed for the evaluation herein. Flash steam geothermal power plants utilize hot water from geothermal reservoirs that flows up through wells within the Earth's crust under its own pressure. The free flowing, hot, pressurized water flows upward decreasing in pressure until some of the hot water boils into steam. The steam is expanded through a steam turbine generator for electric power production. Flash steam power plants are the most common geothermal power plants.

There are negligible air emissions for the flash steam geothermal power plant assumed herein. It is assumed that a dry heat rejection system would be utilized; therefore, the water required for the geothermal plant is negligible.

Figure 6.1-1. U.S. Geothermal Map Estimating Earth Temperature at 3 Kilometers

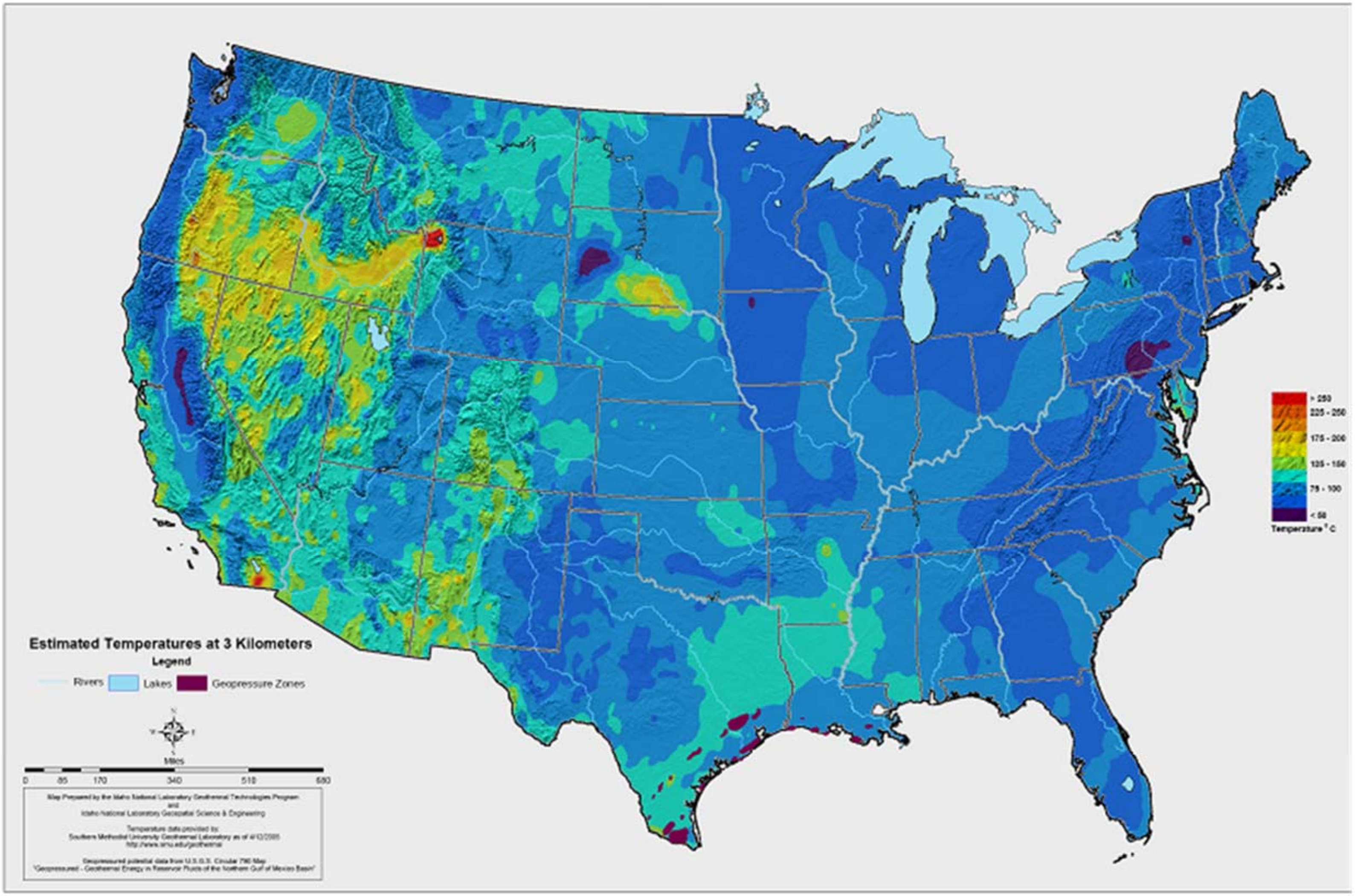
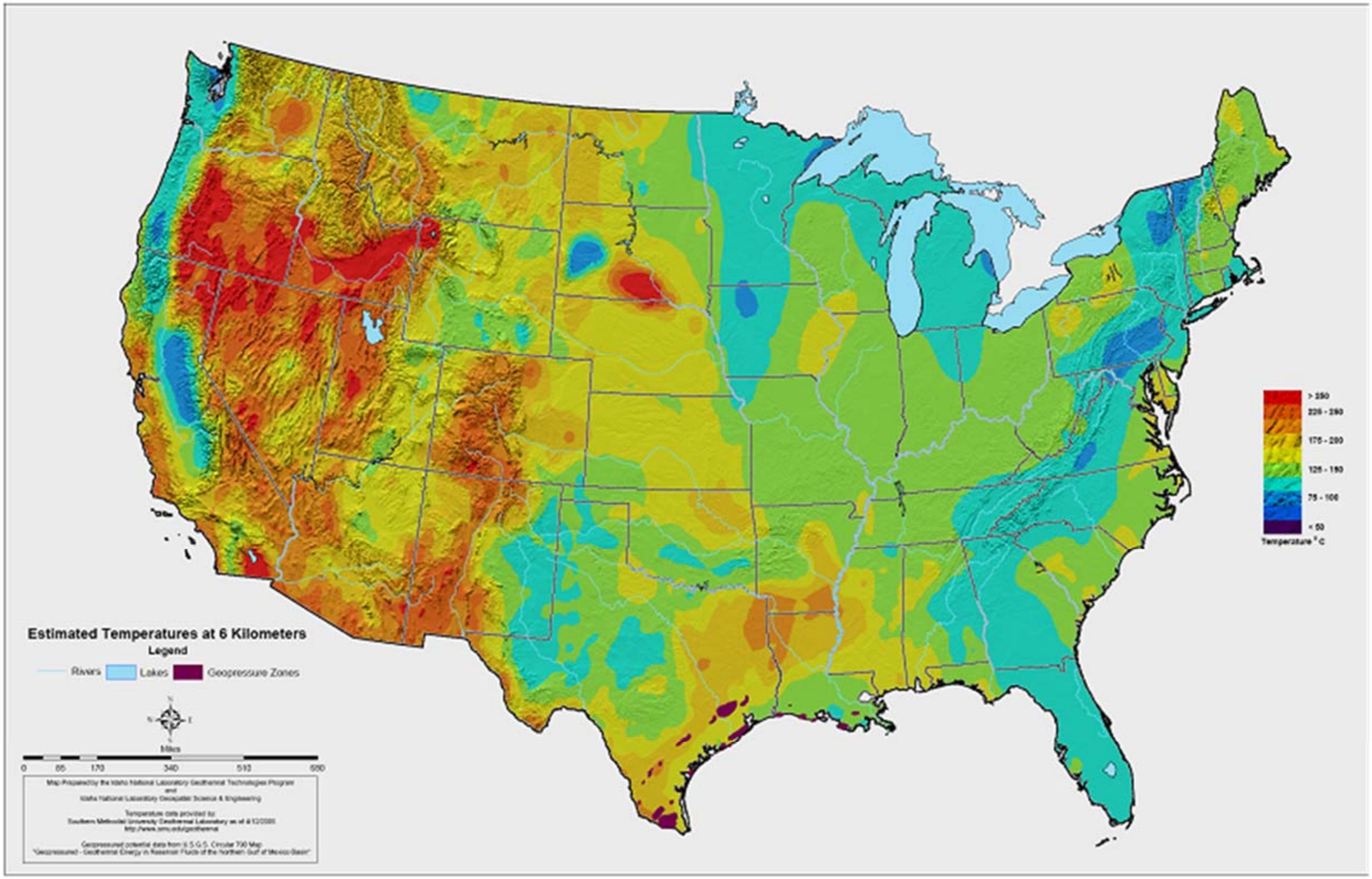


Figure 6.1-2. U.S. Geothermal Map Estimating Earth Temperature at 6 Kilometers



6.2 COMMERCIAL STATUS AND CURRENT MARKET

Geothermal power plants are well-proven and commercially available technologies for power generation. Geothermal power facilities have been implemented throughout the world. Long-term sustainable geothermal power production has been demonstrated at the Lardarello field in Italy since 1913, at the Wairakei field in New Zealand since 1958, and at The Geysers field in California since 1960.

Geothermal heat extraction is similar to extraction processes utilized for the oil and gas, coal, and mining industries. Equipment, knowledge and techniques taken from the industries mentioned above have been adapted and implemented for use in geothermal development, therefore the equipment and technology exists commercially to drill into geothermal reservoirs or permeable rock.

6.3 OPERATIONAL CONSIDERATIONS

Geothermal power stations have much in common with traditional power generating stations. They use many of the same components, including turbines, generators, transformers, and other standard power generating equipment, but also include a pumping and re-injection system.

The primary risk associated with geothermal power generation technology is the integrity of the geothermal energy source and of the geothermal wells constructed for the recovery of this energy. The longevity of a geothermal facility is primarily a function of the geothermal energy source. Some installations may require the drilling of additional wells over the life of the project to continue the supply of energy.

6.3.1 Performance Data

Advances within heat exchanger and steam turbine designs have helped to achieve higher plant efficiencies compared to past geothermal power plants and can use lower temperature water reservoirs which are more abundant. A geothermal power station functions similar to that of a simple cycle power station, but with ramping limitations due to pumping the thermal resource. Table 6.3-1 summarizes the performance data estimated for a 20 MW flash geothermal power plant.

Table 6.3-1. Estimated Geothermal Performance Characteristics

Geothermal Power Performance		
Capacity	MW	20
Economic Maximum	MW	20
Economic Minimum	MW	5
Capacity Factor	%	95
Start-Up Time	Hour	1
Down Time to Warm	Hour	8
Ramp Rate	MW/hr	240

6.3.2 Plant Staffing

Staffing for a 20 MW geothermal power plant is estimated to include approximately three salaried and six hourly staff.

6.4 CONCEPTUAL CAPITAL COST ESTIMATE

The quality of geothermal resources are site specific, and therefore costs of geothermal resources can vary significantly from region to region. HDR has developed estimated project costs based on similar developments/projects and available resources. The conceptual geothermal plant costs include the following equipment/systems:

- Gathering system
- Geothermal pumps
- Steam turbine generator
- Dry ACC
- Circulating water pumps
- Miscellaneous BOP equipment

The conceptual EPC project cost for a 20 MW geothermal plant is estimated to be $2,800/kW for the power island equipment.

Exploration and drilling costs can vary substantially and could be as high as $5,000/kW.

6.5 CONCEPTUAL O&M COSTS

Operating and maintaining a geothermal power island is similar to that of a conventional power island except additional costs are incurred for maintenance of the wells and reservoirs. Maintenance costs include both fixed and variable operating costs, assume a base load operating profile, and include costs to maintain the well heads and gathering systems.

The first year fixed and variable O&M costs are estimated to be $123.98/kW-yr and $9.88/MWh, respectively.

6.6 PROJECT IMPLEMENTATION SCHEDULE

Geothermal power plants typically have a timeline of 3 years from NTP for drilling and equipment and construction contracts through COD. A project implementation schedule is included in Appendix B. The steam turbine generator would be the piece of equipment with the longest lead time (estimated at approximately 20 months). In the past, the main issue of concern for implementing a geothermal power plant has been the difficulty in permitting and leasing geothermal lands, which can lead to long development timeframes.

7.0 PUMPED HYDRO ENERGY STORAGE (PHES)

Pumped hydro energy storage (PHES) facilities store potential energy in the form of water in an upper reservoir, pumped from another reservoir at a lower elevation. During periods of high electricity demand, electricity is generated by releasing the stored water through pump-turbines in the same manner as a conventional hydro station. In periods of low energy demand or low energy cost, historically during the night or weekends, energy is used to reverse the flow and pump the water back up hill into the upper reservoir.

Reversible pump-turbine/generator-motor assemblies can act as both pumps and turbines. Pumped storage stations are a net consumer of electricity, due to hydraulic and electrical losses incurred in the cycle of pumping from the lower reservoir to the upper reservoir. However, these plants typically perform well economically, capturing peak to off-peak energy price differentials, and providing ancillary services to support the overall electric grid.

A 500 MW, 4,500 MWh closed-loop PHES facility has been considered for this evaluation.

7.1 TECHNOLOGY OVERVIEW

PHES is regarded as a mature technology, but does require available topography and water availability.

The generating equipment for the majority of the existing pumped storage plants in the U.S. is the reversible, single-stage Francis pump-turbine. All of the major equipment vendors have significant experience with this type of unit. The technology for single-stage units continues to advance, and a broad range of equipment configurations are available depending upon the available head, site layout, and desired operation.

Variable speed pump-turbines have been used since the early to mid-1990's in Japan and late 1990s in Europe. They are being increasingly considered during project development in Europe and Asia due to a high percentage of renewable energy penetration and the need for load following, ramping, and frequency regulation during periods of excess generation. In California and Arizona, three large pumped storage projects in development are considering variable speed technology almost exclusively due to the growing need for decremental reserves during the day, enabling greater penetration of variable renewable energy resources.

PHES technology is considered partially dispatchable (limited based on reservoir volume) and generally possesses the operational flexibility to provide ancillary services.

7.2 COMMERCIAL STATUS AND CURRENT MARKET

The first U.S. pumped-storage plant was commissioned in 1929 to help balance the grid. Today, there are approximately 40 pumped storage projects operating in the

U.S. and pumped energy storage is considered commercially available and mature as many plants were installed throughout the U.S. in the 1970's and 1980's.

PHES can consist of either open-loop or closed-loop projects, with both types currently operating in the U.S. The distinction between closed-loop and open-loop pumped storage projects is typically defined as:

- Closed-loop pumped storage are projects that are not continuously connected to a naturally flowing water feature; and
- Open-loop pumped storage are projects that are continuously connected to a naturally-flowing water feature.

Closed-loop systems are preferred for new developments as there are often significantly fewer environmental issues, primarily due to the lack of aquatic resource impacts. Projects that are not strictly closed-loop systems can also be desirable, depending upon the project configuration, and whether the project uses existing reservoirs.

7.3 OPERATIONAL CONSIDERATIONS

A PHES facility requires specific geology, the potential to create two reservoirs, and acceptable topography. For the purpose of this study, a 500 MW PHES resource with 9 hours of dispatch capability was assumed within NorthWestern's Montana service territory.

A pumped storage project would typically be designed to have between 6 to 20 hours of hydraulic reservoir storage for operation at full generating capacity. By increasing plant capacity in terms of size and number of units, hydroelectric pumped storage generation can be concentrated and shaped to match periods of highest demand, when it has the greatest value. Existing pumped storage projects range in capacity from 9 to 2,700 MW, and in available energy storage from 87 MWh to 370,000 MWh.

Water-to-wire efficiencies vary based on individual equipment designs, age of the project, and site hydraulics, and include the pump-turbine, generator-motor and transformer efficiencies. Water-to-wire efficiency is typically near 85 – 90 percent for pumping mode and approximately 88 percent for generating mode for fixed speed Francis pump-turbines, resulting in a turnaround or cycle efficiency of approximately 80 percent.

7.3.1 Performance Data

Table 7.3-1 summarizes estimated performance data for a 500 MW, 4,500 MWh PHES system.

Table 7.3-1. Estimated PHES Performance Characteristics

PHES Performance		
Net Capacity	MW	500
Max Storage Limit	MWh	4,500
Min Storage Limit	MWh	0
Discharge Duration	Hours	9
Net Turnaround Efficiency (1st Year)	%	80

7.3.2 Staffing Requirements

Staffing for a 500 MW PHES plant is estimated to include approximately twenty-five to thirty staff.

7.4 CONCEPTUAL CAPITAL COST ESTIMATE

Conceptual EPC project costs for a 500 MW PHES project is estimated to range from $1,700/kW to $3,000/kW. The costs for a variable speed facility are expected to be approximately 20 percent greater than a single speed facility. No land procurement costs or Owner's costs are included.

Land requirements for PHES can vary considerably depending upon the specific project. PHES land requirements can be over a few hundred acres for the reservoir alone. This is highly dependent on the depth of the reservoirs and the amount of storage capacity required to meet peak load periods.

7.5 CONCEPTUAL O&M COSTS

Operations and maintenance costs for pumped energy storage have been estimated assuming a daily dispatch profile with approximately 9 hours of electric production daily.

The estimated fixed and variable O&M costs are based on work for recent confidential pumped storage projects and comparable industry data.

The first year fixed O&M cost is estimated to be $14.55/kW-yr. A variable O&M cost of $0.90/MWH is estimated as a function of the number of starts and stops per day.

Additionally, the variable O&M costs associated with charging the upper reservoir can vary as a function of the energy costs at the time of charging. The variable costs to charge the PHES system have not been included in the technology summary tables herein.

7.6 PROJECT IMPLEMENTATION SCHEDULE

The schedule for a PHES plant can vary considerably depending on a number of factors, including the amount of civil work required to establish the water storage basins and the permitting required to implement the project. The total construction time from receipt of FERC license to commercial operation can be anywhere from 5 years to 8 years for projects similar to that evaluated herein.

8.0 COMPRESSED AIR ENERGY STORAGE (CAES)

Compressed air energy storage (CAES) plants are comparable to PHES plants in terms of their applications, output, and storage capacity. However, instead of pumping water from a lower to an upper pond during periods of excess power, CAES plants compress ambient air which is stored under pressure in an underground cavern.

8.1 TECHNOLOGY OVERVIEW

CAES consists of a series of motor driven compressors capable of filling a storage cavern with air during off-peak, low load hours. During high load, on-peak hours, the stored compressed air is delivered to a series of combustion turbines which are fired with natural gas for power generation. Utilizing pre-compressed air removes the need for a compressor on the combustion turbine, allowing the turbine to operate at high efficiency during peak load periods. This form of CAES is referred to as a diabatic system as the resulting heat from compression is wasted in the process and the air leaving the storage cavern must be reheated prior to expansion in the combustion turbine.

An alternate form of CAES consists of an adiabatic process that recovers and stores the heat from compression in a solid (concrete, stone) or a liquid (oil, molten salt) form that is reused when air is expanded. Natural gas utilization for this technology is limited to that required to supplement for heat lost during the heat storage process. As a result of the conservation of heat, adiabatic storage can achieve higher round trip efficiencies as compared to diabatic storage.

8.2 COMMERCIAL STATUS AND CURRENT MARKET

Only two large scale diabatic CAES plants are currently in operation, including Alabama Electric Cooperative's (AEC) McIntosh plant (rated at 110 MW) which began operation in 1991 and the Huntorf facility located in Huntorf, Germany. A very small, less than 1 MW, adiabatic CAES project is reportedly in operation in Toronto (Toronto Island). The 90 MW / 360 MWh ADELE project in Stassfort, Germany was reportedly placed into service during the summer of 2017 (as confirmed by the DOE Global Energy Storage Database), but little additional information is available regarding the project. Some additional large CAES plants have been proposed but, are not yet beyond the conceptual design phase.

Other projects that have been proposed or are in various stages of development (i.e. not in service) throughout the U.S. and globally include:

- The Western Energy Hub (Magnum) CAES
- PG&E Kern County, CA CAES
- Iowa Stored Energy Park (development of this project has been terminated, though)
- Goderich, Canada, 1.75 MW adiabatic CAES
- Vader Piet, Aruba, 1 MW adiabatic CAES

The equipment used in CAES plants, which includes compressors and gas turbines, is well proven technology used in other mature systems and applications. However, the complete CAES system lacks maturity compared to other power generation technologies due to the limited number of commercially operating plants and the limited number of available technology suppliers.

The integrity and accessibility of a suitable energy storage cavern is very critical to this technology and presents a significant challenge to successful project siting and development.

For the purpose of providing resource modeling inputs herein, a diabatic CAES plant has been evaluated as this design has the most operating experience and therefore the most proven cost and operating information.

8.3 OPERATIONAL CONSIDERATIONS

CAES requires large geologic features, such as a mined salt dome or a previously used natural gas reservoir capable of storing the air at high pressures. This can limit potential resource locations. For the purpose of this study, a nominal 100 MW diabatic CAES resource with 8 hours of dispatch capability was assumed within NorthWestern's service territory.

The major components of a CAES system include a control system, generator, multi-stage air compressors, combustion turbines, underground compressed air storage, and auxiliary equipment (fuel storage and handling, cooling system, electrical systems).

8.3.1 Performance Data

Table 8.3-1 summarizes the estimated performance data for a 100 MW, 800 MWh diabatic CAES system.

Table 8.3-1. Estimated CAES Performance Characteristics

CAES Performance		
Turbine Net Discharge Capacity	MW	100
Max Storage Limit	MWh	800
Min Storage Limit	MWh	0
Charge/Discharge Duration	Hours	8
Compressor/Charging Power	MW	52.63
Turbine Net Heat Rate (1st year), HHV	Btu/kWh	4,500
Round Trip Efficiency	%	50

Adiabatic CAES systems are expected to be able to achieve a round trip efficiency approaching 70% which is improved from the diabatic efficiency noted above.

Diabatic CAES requires initial electrical energy input for air compression and utilizes natural gas for combustion in the turbine. CAES units can swing quickly from generation to compression modes. Compression and generation functions are independent, so ancillary services can be available from both.

8.3.2 Plant Staffing

Staffing for a 100 MW CAES power plant is estimated to include two salaried and six hourly staff.

8.3.3 Environmental Considerations

It is expected that CAES will have emissions similar to that of a simple cycle CT on a lb/mmBtu basis. Dry low–NO_x (DLN) combustion technology can be utilized for control of NO_x emissions on the CT for CAES[27].

Plant water consumption for CAES primarily consists of miscellaneous water consumers required for normal plant staffing and is negligible. Similarly, water discharge is also negligible.

Additional environmental considerations and assessment will be required with a CAES project and the associated underground storage cavern.

8.4 CONCEPTUAL CAPITAL COST ESTIMATE

Installed costs for CAES projects can vary considerably depending on the specific project. The power island for a CAES option is typically small and similar in size to that of a simple cycle CT. Construction of the underground storage reservoir is a significant contributor to the cost of CAES. Aquifers and depleted gas reservoirs are the least expensive storage formations since mining is not necessary. Salt caverns are the most expensive storage formations since solution mining may be necessary before storage.

A limited number of CAES projects have been completed and those that are operating, such as the McIntosh plant, have either received external funding or have vague project scope descriptions associated with cited project costs. CAES EPC project costs are estimated to be in the range of $1,500/kW to $2,300/kW inclusive of easily developable or already available caverns. Costs associated with land acquisition and necessary off-site development work would not be included in these values.

8.5 CONCEPTUAL O&M COSTS

O&M costs for CAES have been estimated assuming a daily dispatch profile of approximately 8 hours of generation. The first year fixed O&M cost is estimated to be $15.27/kW-yr for a 100 MW CAES plant. A variable, O&M cost of $8.53/MWh has been estimated, including the cost of fuel (assumed at $1.50/mmBtu) during the generation of electricity.

Additional variable costs include electric purchases to operate the air compressors. The charging variable O&M cost can vary and is a function of energy costs at the time of charging. These costs have not been included in the technology summary tables included herein.

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[27] NSPS for CO2 would also apply to CAES plants.

8.6 PROJECT IMPLEMENTATION SCHEDULE

The project schedule for a CAES plant is highly dependent on the manufacturer's lead times for equipment. For the most part, a project should be able to be implemented in a time frame similar to, but slightly longer than, that of a simple cycle CT plant provided the compressed air storage cavern is available. Permitting of the air storage cavern prior to the implementation of the project can be expected to involve an extended period of time. A conceptual project implementation schedule is included in Appendix B.

9.0 BATTERY ENERGY STORAGE SYSTEM (BESS)

Grid-connected battery energy storage systems (BESS) are maturing, with increasing commercial deployment in the electric industry.

BESS can be used for overall electricity demands by the electric utility or to help minimize peak demand, smooth load variations due to renewables integration, and improving local grid resilience and availability.

9.1 TECHNOLOGY OVERVIEW

Lithium Ion (Li-ion) batteries utilize the exchange of lithium ions between electrodes to charge and discharge the battery. When the battery is in use (discharge) the charged electrons move from the anode to the cathode and in the process, energize the connected circuit. Electrons flow in the reverse direction during a charge cycle when energy is drawn from the grid. Due to its characteristics, Li-ion technology is well suited for fast-response applications like frequency regulation, frequency response, and short-term spinning reserve applications. Additionally, compared to other BESS, the Li-ion technology provides the highest energy storage density resulting in its adoption in several different markets ranging from consumer electronics to transportation (electric vehicles) and power generation.

Vanadium redox flow batteries are based on the redox reaction between electrolytes in the system. The system consists of two liquid electrolytes in tanks (vanadium ions in different oxidation states) separated by a proton exchange membrane. The membrane permits ion flow but prevents mixing of the liquids. Electrical contact is made through inert conductors in the liquids. As the ions flow across the membrane, an electrical current is induced in the conductors to charge the battery. This process is reversed during the discharge cycle. The liquid electrolyte used for charge-discharge reactions is stored externally and pumped through the cell. A typical vanadium redox flow battery includes large electrolyte storage tanks and pumps limiting this technology to certain applications.

9.2 COMMERCIAL STATUS AND CURRENT MARKET

Li-ion battery technology is a relatively mature technology, having been first proposed in 1970 and released commercially in 1991. The market for utility-scale energy storage systems is relatively early in development, but it is growing and evolving quickly.

The increasing demand for battery storage in consumer electronics and the transportation sector as well as the emerging demand from the energy sector are propelling advances in the technology and manufacturing capacity for Li-ion. This is also aiding the trend of declining initial capital cost for this technology.

While the first successful demonstration project for a vanadium redox flow battery system was in the 1980's, today, there are only a few systems in operation worldwide. The vanadium redox flow industry is moving toward pre-packaged systems in containers to better compete with Li-ion systems. There is significant interest in these vanadium redox flow systems as they have a high cycle life, have a large allowable temperature range, and longer storage durations.

Other battery storage technologies include sodium sulfur, lead-acid, zinc iron and zinc bromine flow technologies; however, Li-ion is the most prominent and widely used for utility scale BESS. This is primarily due to technology maturity and risks that are better understood, the number of established and credit worthy Li-ion battery manufacturers in the market place, their ability to provide long term performance guarantees and warranties typically required by the electric utility industry, and the existence of proven integrators that have a successful track record of installing turnkey EPC BESS projects for several years.

9.2.1 Current Market Influences

On February 15, 2018 the Federal Energy Regulatory Commission (FERC) issued FERC Order 841 that directs the operators of wholesale markets, Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) to develop market rules for energy storage to participate in wholesale energy, capacity, and ancillary service markets. The order essentially allows an energy storage resource to be dispatched and to be able to set market clearing places as both a buyer and seller. RTOs and ISOs have nine months to file tariffs that comply with the order and another year to implement the tariff provisions.

The FERC Order essentially removes the barriers for market entry and levels the playing field for BESS with other resources. However, how the RTOs implement Order 841 will affect a storage system's market value and adoption rates.

9.3 OPERATIONAL CONSIDERATIONS

For this study, a proxy 25 MW, 100 MWh BESS with one discharge cycle per day was considered. The basis of capacity sizing was to provide NorthWestern with about 4 hours of dispatch capability enabling demand management/load shifting as well as local restoration efforts in the case of outage conditions.

Numerous BESS integrators in the marketplace were contacted[28] for technical and commercial data. Technical information as well as experience, scope of supply, schedule of delivery, pricing and O&M details were solicited from the integrators that responded. Information received was specific to Li-ion technology, largely due to its prevalence in the industry. Some information was also gathered from vanadium redox flow battery integrators.

Major components of a BESS station include the battery containers, battery management system (BMS), power conversion system (PCS) enclosures, plant control systems, and balance of plant systems including the cooling system, station load transformers, pad mounted medium/high voltage transformers, and grid interconnection gear with metering, site utilities, foundations and plant fencing.

[28] Greensmith Energy, ABB Inc., Renewable Energy Systems Americas Inc., S&C Electric Company, AES Energy Storage, Uni Energy Technologies, ViZn Energy Systems, Vinox Energy and Primus Power.

9.3.1 Performance Data

Table 9.3-1 summarizes estimated performance data for a typical 25 MW, 100 MWh BESS.

Table 9.3-1. Estimated BESS Performance Characteristics

Parameter / Technology	Lithium Ion	Vanadium redox flow
Capacity (MW)	25	25
Max Storage Limit (MWh)	100	100
Min Storage Limit (MWh)	2	2
Leakage Rate (% /hr)	0.05%	0.00%
Discharge Duration (hrs)	4	4
Recharge Time (hrs)	4	6.5
Round Trip Efficiency	85%	73%
Cycle Life (1 cycle/day 20 yrs)	7,500	Over 7,500
Expected Annual Availability	96%	95%
Ancillary Service Capability	Reg up/down, spin/non-spin, reserve	Reg up/down, spin/non-spin, reserve

An important consideration of BESS is round trip energy efficiency, which is the amount of AC energy the system can deliver relative to the amount of AC energy used by the system during the preceding charge. Losses experienced in the charge/discharge cycle include those from the PCS (inverters), heating and ventilation, control system losses, and auxiliary losses.

The Li-ion technology experiences degradation both in terms of capacity and round-trip efficiency with time due to a variety of factors including number of full charge/discharge cycles and environmental exposure. Typically, integrators employ augmentation strategies such as oversizing and/or periodic replacement, to ensure the grid connected BESS is supplying the necessary MW, MWh and expected cycle life during the performance period. To meet electric utility customer needs, BESS integrators are willing to provide a guaranteed equipment life of about 20 years with an appropriate augmentation strategy. Each battery OEM and integrator strategy can be different and there are no set industry standards.

Vanadium redox flow batteries on the other hand, do not experience significant performance degradation due to the fact that the charged electrons are stored in the liquid (vanadium) form that has limited self-discharge characteristics and they also exhibit almost no degradation when the system is left discharged for long periods of time. However, given the large volume of solution that must be pumped, the auxiliary load and recharge time of a similarly sized flow battery system is higher when compared to the Li-ion technology.

9.3.2 Plant Staffing

Staffing for a 25 MW, 100 MWh BESS installation generally assumes the utilization of a remote monitoring/operating system. No additional staffing requirements are included for the BESS options.

9.4 CONCEPTUAL CAPITAL COST ESTIMATES

The capital cost for an installed BESS includes the costs of the energy storage equipment, power conversion equipment, power control system, balance of system including site utilities, electric scope to the high side of the GSU transformer, and installation costs.

For Li-Ion systems, battery cells are arranged and connected into strings, modules, and packs which are then packaged into a DC system meeting the required power and energy specifications of the project. The DC system includes internal wiring, temperature and voltage monitoring equipment, and an associated battery management system responsible for managing low-level safety and performance of the DC battery system. For vanadium redox flow batteries, the DC system costs include electrolyte storage tanks, membrane power stacks, and container costs for the system along with associated cycling pumps and battery management controls. Each system would involve a PCS to convert the produced DC power to AC power for ultimate grid utilization.

Conceptual level capital costs for a 25 MW/100 MWh Li-ion and vanadium redox flow BESS are estimated at $1,660/kW and $1,700/kW, respectively.

9.5 CONCEPTUAL O&M COSTS

The major component of the O&M cost for a Li-ion BESS system is related to energy and capacity augmentation. Augmentation maintains the BESS capability to serve the Owner's requirement for the term of the agreement. These costs are typically covered in the fixed O&M costs. Additional fixed O&M costs typically include:

- 24x7 remote monitoring
- Remote troubleshooting
- Performing scheduled maintenance activities, inverter replacements, emergency and unscheduled maintenance support
- Periodic reporting, training and continuous improvement
- Software licensing and updates
- HVAC maintenance
- Auxiliary electrical loads
- Landscaping
- Mechanical/electrical inspections and updates.

For flow battery systems, maintenance services typically include:

- Power stack and pump inspection and replacement
- Inverter replacements
- Sensor calibration
- Cooling systems service
- Tightening of plumbing fixtures and mechanical and electrical connections
- Periodic chemistry refresh and full discharge cycles to refresh capacity.

At current, the equipment suppliers are providing fixed O&M services directly.

For Li-ion BESS, the variable O&M costs include a discharging or cycling charge which is the variable component of the augmentation service agreement[29]. The total annual augmentation costs are estimated based on 1 full cycle/day discharge rate. As mentioned, no staffing costs are included.

For the Li-ion BESS, conceptual first year fixed and variable O&M costs are estimated at $39.61/kW-yr and $7.00/MWh, respectively.

For the vanadium redox flow BESS, conceptual first year fixed O&M costs are estimated at $34.01/kW-yr[30]. There are typically no variable O&M costs associated with this technology.

The variable O&M costs do not include electric purchases made to charge the batteries. The charging cost can vary and is a function of energy costs at the time of charging.

9.6 PROJECT IMPLEMENTATION SCHEDULE

The BESS integrator's scope of supply typically includes most of the systems up to the inverter terminal where AC power is available to the GSU transformer. Accordingly, the BESS integrator can deliver the major systems within 9 months from NTP. Additional site engineering, foundation and substructure work, permitting, site utilities and utility interconnection work is generally completed by a general/EPC contractor. A typical 25 MW BESS project can be commissioned and in commercial operation within 14 months from NTP. A typical project implementation schedule for a 25 MW BESS installation is included in Appendix B.

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[29] BESS O&M costs are sometimes expressed on a fixed O&M basis only. While the costs expressed herein include both a fixed and variable component, the li-ion BESS technology could be evaluated based on a fixed O&M component only. This would be accomplished by incorporating the variable O&M component into the fixed costs based on one cycle per day and applying associated operational constraints in the model.

[30] This is the second year cost as the first year fixed O&M component is typically included in the project capital costs.

10.0 POTENTIAL COST TRENDS

It is anticipated that, with increasing experience in the marketplace through widespread application of a certain power generation technology, the initial capital costs would decrease as design, fabrication, and installation of that technology becomes more mature and better understood. To understand the impact of technology maturity and potential capital cost trends over time, potential cost trend curves were developed using data from the Energy Information Administration's (EIA) 2018 Annual Energy Outlook (AEO) National Energy Modeling System (NEMS). Cost forecasting data from NEMS was applied to the estimated capital costs developed for this report as a basis for forecasting future cost trends. All costs are referenced in 2018 US dollars and are forecasted from 2018 to 2050. In instances where the NEMS forecasted cost projections did not start until 2020 or 2021, costs were estimated to be unchanged from 2018 until the start of the NEMS forecast. The figures below summarize potential cost trends for the generation and storage technologies considered in this evaluation.

Figure 10-1. Potential Cost Trends – Renewable and Storage Technologies

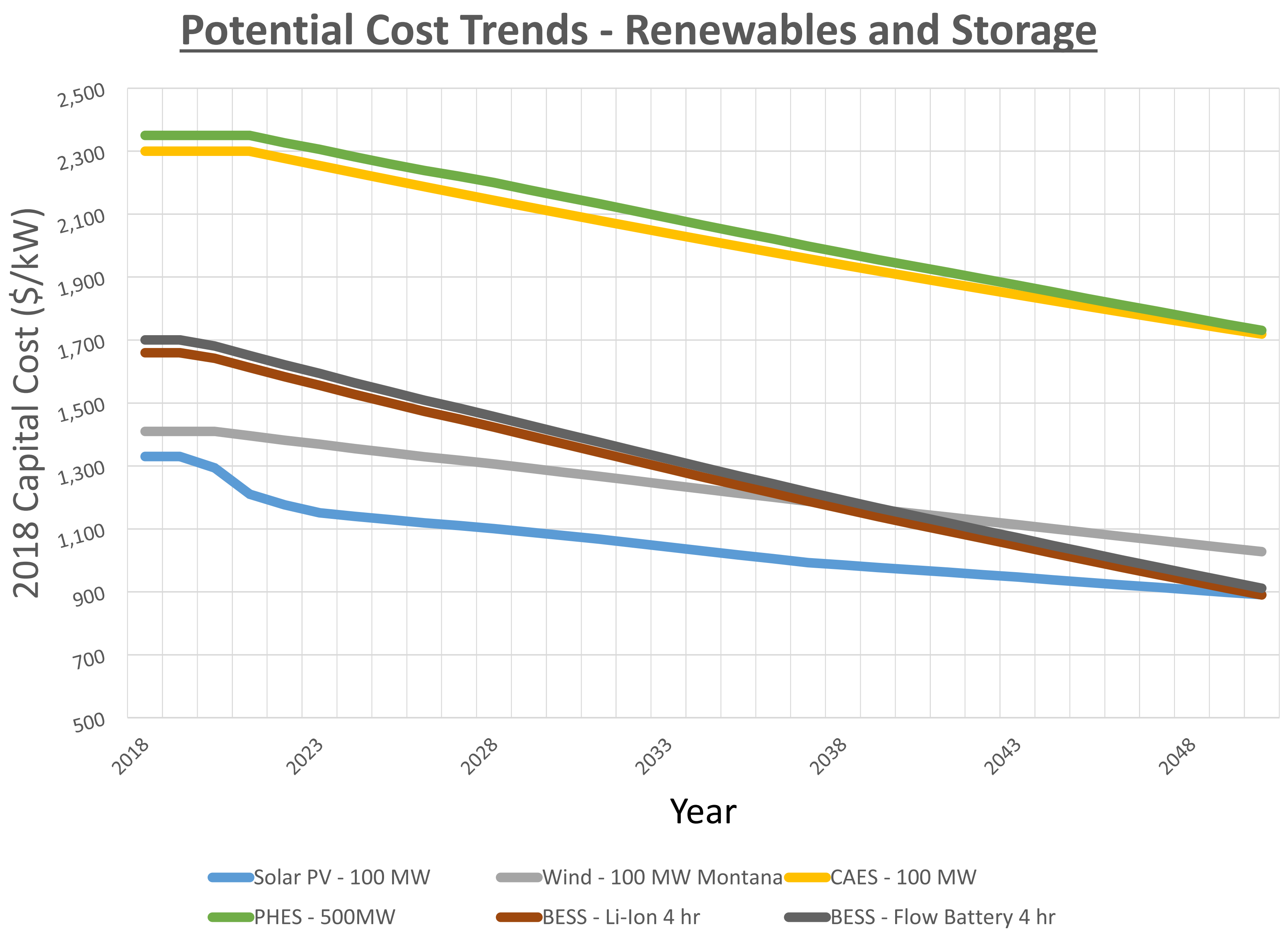
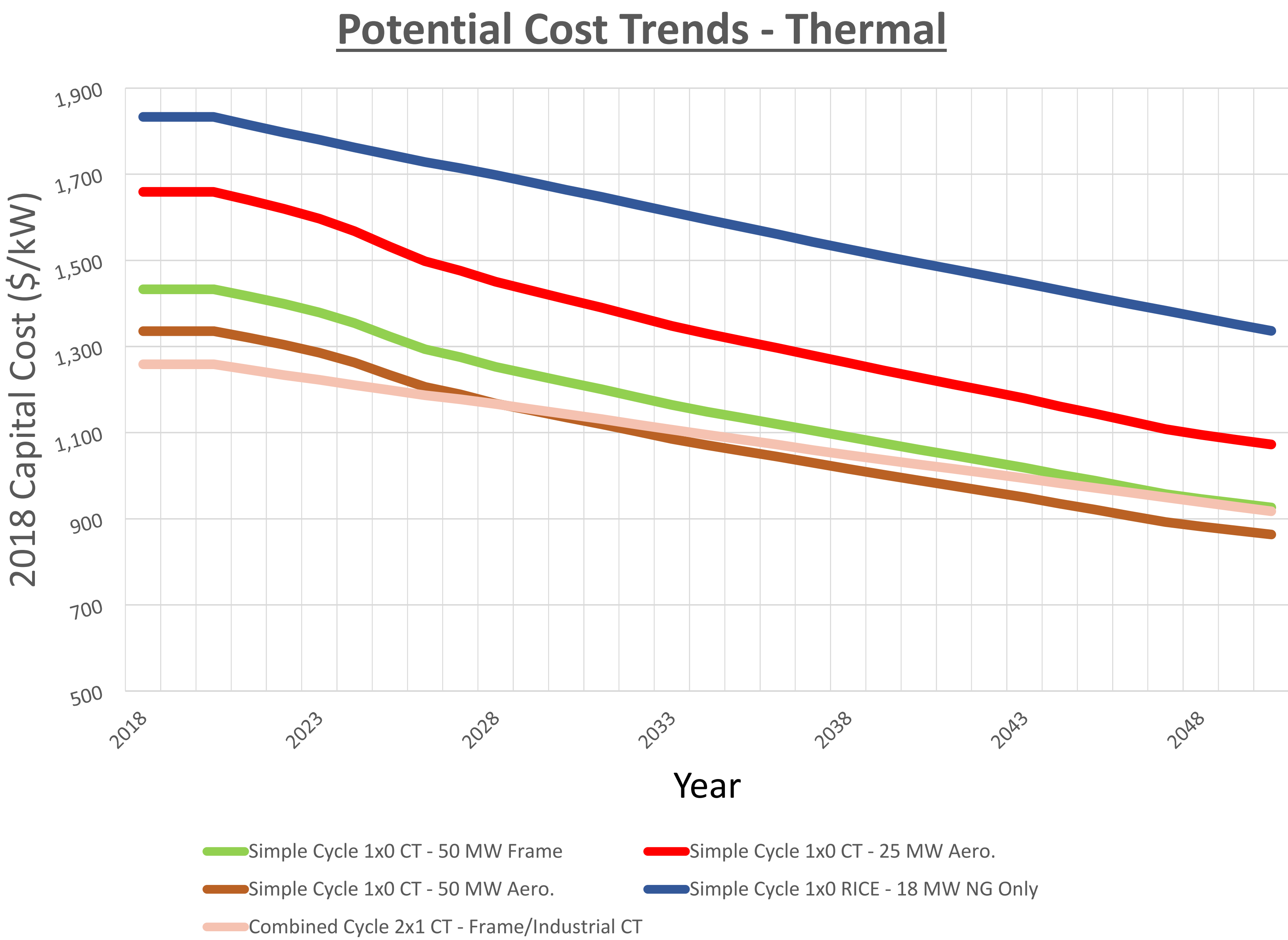


Figure 10-2. Potential Cost Trends – Thermal Technologies



Appendix A

Conceptual Project Cost Estimate Summary Sheets

(Thermal Options)

Simple Cycle 1x0 CT - 50 MW Frame

Print Date: 4/9/2018

LOCATION: 2018 IRP
HDR PROJECT # 10103432
PLANT TYPE: Simple Cycle
CLIENT: NorthWestern Energy
ESTIMATE TYPE: Conceptual
LEAD ESTIMATOR: DDG

STATUS DATE: 30-Mar-18

COST DATE BASIS: March 2018	BID DUE DATE:	TECHNOLOGY: Gas Turbine	
	LNTP Const. MOB:	NET MW RATING (AVG): 90	BOILER: NA
	FNTP:	NET MW ECAR:	STEAM TURBINE: NA
ESCALATION BASIS (APR):	COMMERCIAL OP. DATE: Jan-2019	FUEL TYPE: Natural Gas	COOLING TYPE: Fin Fan

	TOTAL COSTS						
DIVISION OF WORK	**Procurement Major Equipment**	**Contractor Material $**	**Contractor Labor $**	**Contractor Labor Hours**	**Subcontractor or Other $**	**Project Total $**	**%**
Demolition & Sitework	$0	$565,414	$252,404	5,934	0	$817,818	1.2%
Deep Foundations & Concrete	$0	$739,149	$519,471	12,246	0	$1,258,620	1.9%
Architectural & Metals	$0	$2,476,795	$210,644	4,161	0	$2,687,439	4.1%
Piping, Valves, Support, Accessories	$0	$1,505,737	$816,680	15,210	0	$2,322,417	3.5%
Mechanical Insulation & Lagging	$0	$75,362	$74,741	1,344	0	$150,102	0.2%
Combustion Turbine Generator	$20,500,000	$0	$494,572	9,300	0	$20,994,572	32.0%
Steam Generator	$0	$0	$0	0	0	$0	0.0%
AQCS Equipment	$2,730,000	$0	$249,945	4,700	0	$2,979,945	4.5%
Stack	$0	$0	$0	0	0	$0	0.0%
BOP Mechanical Equipment	$0	$1,879,646	$132,462	2,415	347,052	$2,359,161	3.6%
Electrical Equipment	$846,300	$1,215,895	$171,644	3,565	0	$2,233,839	3.4%
Electrical Commodities	$0	$900,963	$524,491	10,574	0	$1,425,454	2.2%
High Voltage Electrical & Substation	$0	$0	$0	0	0	$0	0.0%
High Voltage Transmission	$0	$0	$0	0	0	$0	0.0%
Controls & Instrumentation	$0	$1,170,977	$200,690	4,168	0	$1,371,667	2.1%
Subtotal Direct Costs:	$24,076,300	$10,529,938	$3,647,744	73,616	$347,052	$38,601,035	58.8%
Sales Tax	0	0			0	$0	0.0%
Total Direct Cost	$24,076,300	$10,529,938	$3,647,744	73,616	$347,052	$38,601,035	58.8%
Construction Indirects & Services							
- Construction Equipment					$4,208,079	$4,208,079	6.4%
- Construction Field Staff (Construction Mgmt.)					$2,655,892	$2,655,892	4.0%
- Construction Field Staff Expenses					$597,916	$597,916	0.9%
- Construction Permits					$8,000	$8,000	0.0%
- Construction Testing					$375,000	$375,000	0.6%
- Performance Testing					$317,800	$317,800	0.5%
- Preop Testing, Start-up					$601,302	$601,302	0.9%
- Consumable Materials & Safety Supplies					$154,593	$154,593	0.2%
- Field Office Expense					$229,181	$229,181	0.3%
- Site Safety					$229,458	$229,458	0.3%
- Small Tools					$650,579	$650,579	1.0%
- Start up Supervision					$38,653	$38,653	0.1%
- Support Craft & Site Services					$684,793	$684,793	1.0%
- Long Haul Shipping					$300,000	$300,000	0.5%
- Temporary Facilities					$307,309	$307,309	0.5%
- Temporary Utilities					$894,182	$894,182	1.4%
Subtotal Construction Indirects & Services		$0	$0	0	$12,252,737	$12,252,737	18.7%
Total Construction Cost	$24,076,300	$10,529,938	$3,647,744	73,616	$12,599,789	$50,853,771	77.4%
Project Indirects							
- Power Plant Design Engineering					$3,088,083	$3,088,083	4.7%
- Project Management (Home Ofc PM & Procurement)					$386,010	$386,010	0.6%
Sub-Total Project Indirects	$0	$0	$0	0	$3,474,093	$3,474,093	
EPC Insurance & Misc Costs							
- Builders All Risk Insurance					$0	$0	0.0%
- Comprehensive General Liability (CGL) Insurance					$0	$0	0.0%
- Warranty Reserve					$0	$0	0.0%
Sub-Total EPC Insurance & Misc. Costs	$0	$0	$0	0	$0	$0	
Total EPC Project Indirect Cost	$0	$0	$0	0	$3,474,093	$3,474,093	5.3%
Sub-Total	$24,076,300	$10,529,938	$3,647,744	73,616	$16,073,882	$54,327,865	82.7%
- Escalation (Equip, Matls. & Labor)	$0	$0	$0		$0	$0	0.0%
Sub-Total	$24,076,300	$10,529,938	$3,647,744	73,616	$16,073,882	$54,327,865	82.7%
- EPC Contingency	$3,429,630	$1,052,994	$364,774		$1,607,388	$6,454,786	9.8%
- EPC G&A					$1,629,836	$1,629,836	2.5%
- EPC Fee					$3,259,672	$3,259,672	5.0%
TOTAL EPC Project Cost	$27,505,930	$11,582,932	$4,012,518	73,616	$22,570,778	$65,672,159	100.0%
EPC Price per kW						$734	

Simple Cycle 1x0 CT - 25 MW Aeroderivative

Print Date: 4/9/2018

LOCATION:	2018 IRP
HDR PROJECT #	10072178
PLANT TYPE:	Simple Cycle
CLIENT:	NorthWestern Energy
ESTIMATE TYPE:	Conceptual
LEAD ESTIMATOR:	DDG

60.0

STATUS DATE: 30-Mar-18

COST DATE BASIS: March 2018	BID DUE DATE:	TECHNOLOGY:	Gas Turbine	
	LNTP Const. MOB:	NET MW RATING:	27	BOILER: NA
	FNTP:	NET MW ECAR:		STEAM TURBINE: NA
ESCALATION BASIS (APR):	COMMERCIAL OP. DATE:	FUEL TYPE:	Natural Gas	COOLING TYPE: Fin Fan

	TOTAL COSTS						
DIVISION OF WORK	**Procurement Major Equipment**	**Contractor Material $**	**Contractor Labor $**	**Contractor Labor Hours**	**Subcontractor or Other $**	**Project Total $**	**%**
Demolition & Sitework	$0	$240,325	$107,741	2,534	0	$348,066	0.8%
Deep Foundations & Concrete	$0	$388,642	$291,630	6,875	0	$680,271	1.5%
Architectural & Metals	$0	$1,449,853	$134,482	2,650	0	$1,584,335	3.6%
Piping, Valves, Support, Accessories	$0	$967,963	$618,767	11,524	0	$1,586,730	3.6%
Mechanical Insulation & Lagging	$0	$57,922	$56,569	1,037	0	$114,491	0.3%
Combustion Turbine Generator	$16,745,000	$0	$478,618	9,000	0	$17,223,618	38.8%
Steam Generator	$0	$0	$0	0	0	$0	0.0%
AQCS Equipment	$0	$0	$239,309	4,500	0	$239,309	0.5%
Chimney	$0	$0	$0	0	0	$0	0.0%
BOP Mechanical Equipment	$0	$875,110	$65,793	1,192	158,490	$1,099,394	2.5%
Electrical Equipment	$335,657	$661,668	$153,966	3,198	0	$1,151,291	2.6%
Electrical Commodities	$0	$464,198	$292,627	5,838	0	$756,825	1.7%
High Voltage Electrical & Substation	$0	$0	$0	0	0	$0	0.0%
High Voltage Transmission	$0	$0	$0	0	0	$0	0.0%
Controls & Instrumentation	$0	$1,212,873	$195,131	4,053	0	$1,408,004	3.2%
Subtotal Direct Costs:	$17,080,657	$6,318,553	$2,634,634	52,399	$158,490	$26,192,334	59.1%
Sales Tax	0	0			0	$0	0.0%
Total Direct Cost	$17,080,657	$6,318,553	$2,634,634	52,399	$158,490	$26,192,334	59.1%
Construction Indirects & Services							
- Construction Equipment					$2,854,851	$2,854,851	6.4%
- Construction Field Staff (Construction Mgmt.)					$1,865,386	$1,865,386	4.2%
- Construction Field Staff Expenses					$421,811	$421,811	1.0%
- Construction Permits					$47,829	$47,829	0.1%
- Construction Testing					$350,833	$350,833	0.8%
- Performance Testing					$389,745	$389,745	0.9%
- Preop Testing, Start-up					$601,302	$601,302	1.4%
- Consumable Materials & Safety Supplies					$110,038	$110,038	0.2%
- Field Office Expense					$194,956	$194,956	0.4%
- Site Safety					$205,481	$205,481	0.5%
- Small Tools					$644,608	$644,608	1.5%
- Start up Supervision					$38,653	$38,653	0.1%
- Support Craft & Site Services					$582,601	$582,601	1.3%
- Long Haul Shipping					$300,000	$300,000	0.7%
- Temporary Facilities					$295,899	$295,899	0.7%
- Temporary Utilities					$791,174	$791,174	1.8%
Subtotal Construction Indirects & Services		$0	$0	0	$9,695,168	$9,695,168	21.9%
Total Construction Cost	$17,080,657	$6,318,553	$2,634,634	52,399	$9,853,658	$35,887,501	80.9%
Project Indirects							
- Power Plant Design Engineering					$2,095,387	$2,095,387	4.7%
- Project Management (Home Ofc PM & Procurement)					$261,923	$261,923	0.6%
Sub-Total Project Indirects	$0	$0	$0	0	$2,357,310	$2,357,310	
EPCM Insurance & Misc Costs							
- Builders All Risk Insurance					$0	$0	0.0%
- Comprehensive General Liability (CGL) Insurance					$0	$0	0.0%
- Warranty Reserve					$0	$0	0.0%
Sub-Total EPCM Insurance & Misc. Costs	$0	$0	$0	0	$0	$0	
Total EPCM Project Indirect Cost	$0	$0	$0	0	$2,357,310	$2,357,310	5.3%
Sub-Total	$17,080,657	$6,318,553	$2,634,634	52,399	$12,210,968	$38,244,812	86.3%
- Escalation (Equip, Matls. & Labor)	$0	$0	$0		$0	$0	0.0%
Sub-Total	$17,080,657	$6,318,553	$2,634,634	52,399	$12,210,968	$38,244,812	86.3%
- EPCM Contingency	$535,916	$631,855	$263,463		$1,221,097	$2,652,331	6.0%
- EPCM G&A					$1,147,344	$1,147,344	2.6%
- EPCM Fee					$2,294,689	$2,294,689	5.2%
TOTAL EPCM Project Cost	$17,616,572	$6,950,408	$2,898,097	52,399	$16,874,098	$44,339,176	100.0%
EPC Price per kW						$1,624	

Owners Cost							
- Gas Supply Line					$0	$0	0.0%
TOTAL EPCM Project Cost (w/Owners	$17,616,572	$6,950,408	$2,898,097	$52,399	$16,874,098	$44,339,176	100.0%
EPC Price per kW (w/Owner's Cost)						$1,624	

Total Craft Labor Hours	52,399	Senior Project Manager:	
Average Craft $/Labor Hour w/o Escalation	$50.28	Project Manager:	R.W. Nagel
Field Labor Type	Open Shop	Construction Lead:	
Labor Productivity Factor	1.00	Chief Estimator:	D.D. Gayeski

Simple Cycle 1x0 CT - 50 MW Aeroderivative

Print Date: 4/9/2018

LOCATION:	2018 IRP
HDR PROJECT #	10103432
PLANT TYPE:	Simple Cycle
CLIENT:	NorthWestern Energy
ESTIMATE TYPE:	Conceptual
LEAD ESTIMATOR:	DDG

60.0

STATUS DATE: 06-Apr-18

COST DATE BASIS: April 2018	BID DUE DATE:	TECHNOLOGY:	Gas Turbine		
	LNTP Const. MOB:	NET MW RATING:	50	BOILER:	NA
	FNTP:	NET MW ECAR:		STEAM TURBINE:	NA
ESCALATION BASIS (APR):	COMMERCIAL OP. DATE:	FUEL TYPE:	Natural Gas	COOLING TYPE:	Fin Fan

DIVISION OF WORK	TOTAL COSTS Procurement Major Equipment	Contractor Material $	Contractor Labor $	Contractor Labor Hours	Subcontractor or Other $	Project Total $	%
Demolition & Sitework	$0	$342,082	$159,543	3,754	0	$501,625	0.8%
Deep Foundations & Concrete	$0	$448,355	$336,438	7,931	0	$784,792	1.3%
Architectural & Metals	$0	$2,330,137	$171,927	3,363	0	$2,502,064	4.1%
Piping, Valves, Support, Accessories	$0	$1,007,138	$782,243	14,568	0	$1,789,381	3.0%
Mechanical Insulation & Lagging	$0	$61,243	$61,748	1,133	0	$122,991	0.2%
Combustion Turbine Generator	$25,344,000	$0	$616,886	11,600	0	$25,960,886	43.0%
Steam Generator	$0	$0	$0	0	0	$0	0.0%
AQCS Equipment	$0	$0	$239,309	4,500	0	$239,309	0.4%
Chimney	$0	$0	$0	0	0	$0	0.0%
BOP Mechanical Equipment	$0	$1,332,111	$99,269	1,802	264,421	$1,695,801	2.8%
Electrical Equipment	$560,000	$901,407	$189,555	3,937	0	$1,650,962	2.7%
Electrical Commodities	$0	$678,092	$430,455	8,583	0	$1,108,547	1.8%
High Voltage Electrical & Substation	$0	$0	$0	0	0	$0	0.0%
High Voltage Transmission	$0	$0	$0	0	0	$0	0.0%
Controls & Instrumentation	$0	$1,747,989	$231,754	4,813	0	$1,979,743	3.3%
Subtotal Direct Costs:	$25,904,000	$8,848,554	$3,319,126	65,985	$264,421	$38,336,101	63.5%
Sales Tax	0	0			0	$0	0.0%
Total Direct Cost	$25,904,000	$8,848,554	$3,319,126	65,985	$264,421	$38,336,101	63.5%
Construction Indirects & Services							
- Construction Equipment					$3,068,630	$3,068,630	5.1%
- Construction Field Staff (Construction Mgmt.)					$2,181,589	$2,181,589	3.6%
- Construction Field Staff Expenses					$492,253	$492,253	0.8%
- Construction Permits					$59,906	$59,906	0.1%
- Construction Testing					$248,000	$248,000	0.4%
- Performance Testing					$483,199	$483,199	0.8%
- Preop Testing, Start-up					$601,302	$601,302	1.0%
- Consumable Materials & Safety Supplies					$138,568	$138,568	0.2%
- Field Office Expense					$208,646	$208,646	0.3%
- Site Safety					$215,072	$215,072	0.4%
- Small Tools					$646,997	$646,997	1.1%
- Start up Supervision					$38,653	$38,653	0.1%
- Support Craft & Site Services					$623,478	$623,478	1.0%
- Long Haul Shipping					$300,000	$300,000	0.5%
- Temporary Facilities					$300,463	$300,463	0.5%
- Temporary Utilities					$801,040	$801,040	1.3%
Subtotal Construction Indirects & Services		$0	$0	0	$10,407,795	$10,407,795	17.2%
Total Construction Cost	$25,904,000	$8,848,554	$3,319,126	65,985	$10,672,216	$48,743,896	80.8%
Project Indirects							
- Power Plant Design Engineering					$3,066,888	$3,066,888	5.1%
- Project Management (Home Ofc PM & Procurement)					$383,361	$383,361	0.6%
Sub-Total Project Indirects	$0	$0	$0	0	$3,450,249	$3,450,249	
EPCM Insurance & Misc Costs							
- Builders All Risk Insurance					$0	$0	0.0%
- Comprehensive General Liability (CGL) Insurance					$0	$0	0.0%
- Warranty Reserve					$0	$0	0.0%
Sub-Total EPCM Insurance & Misc. Costs	$0	$0	$0	0	$0	$0	
Total EPCM Project Indirect Cost	$0	$0	$0	0	$3,450,249	$3,450,249	5.7%
Sub-Total	$25,904,000	$8,848,554	$3,319,126	65,985	$14,122,465	$52,194,145	86.5%
- Escalation (Equip, Matls. & Labor)	$0	$0	$0		$0	$0	0.0%
Sub-Total	$25,904,000	$8,848,554	$3,319,126	65,985	$14,122,465	$52,194,145	86.5%
- EPCM Contingency	$816,320	$884,855	$331,913		$1,412,246	$3,445,335	5.7%
- EPCM G&A					$1,565,824	$1,565,824	2.6%
- EPCM Fee					$3,131,649	$3,131,649	5.2%
TOTAL EPCM Project Cost	$26,720,320	$9,733,410	$3,651,039	65,985	$20,232,184	$60,336,953	100.0%
EPC Price per kW						$1,200	

Owners Cost							
- Gas Supply Line					$0	$0	0.0%
TOTAL EPCM Project Cost (w/Owners	$26,720,320	$9,733,410	$3,651,039	65,985	$20,232,184	$60,336,953	100.0%
EPC Price per kW (w/Owner's Cost)						$1,200	

Total Craft Labor Hours	65,985	Senior Project Manager:	
Average Craft $/Labor Hour w/o Escalation	$50.30	Project Manager:	R.W. Nagel
Field Labor Type	Open Shop	Construction Lead:	
Labor Productivity Factor	1.00	Chief Estimator:	D.D. Gayeski

Print Date: 4/9/2018

Simple Cycle 1x0 CT - 50 MW Aeroderivative Dual Fuel (NG/FO)

LOCATION:	2018 IRP
HDR PROJECT #	10103432
PLANT TYPE:	Simple Cycle
CLIENT:	NorthWestern Energy
ESTIMATE TYPE:	Conceptual
LEAD ESTIMATOR:	DDG

60.0

STATUS DATE: 06-Apr-18

COST DATE BASIS: April 2018	BID DUE DATE:	TECHNOLOGY: Gas Turbine	
	LNTP Const. MOB:	NET MW RATING: 50	BOILER: NA
	FNTP:	NET MW ECAR:	STEAM TURBINE: NA
ESCALATION BASIS (APR):	COMMERCIAL OP. DATE:	FUEL TYPE: Natural Gas/Fuel Oil	COOLING TYPE: Fin Fan

	TOTAL COSTS						
DIVISION OF WORK	**Procurement Major Equipment**	**Contractor Material $**	**Contractor Labor $**	**Contractor Labor Hours**	**Subcontractor or Other $**	**Project Total $**	**%**
Demolition & Sitework	$0	$441,082	$189,472	4,414	236,000	$866,554	1.3%
Deep Foundations & Concrete	$0	$469,085	$350,913	8,272	0	$819,998	1.2%
Architectural & Metals	$0	$2,330,137	$171,927	3,363	0	$2,502,064	3.7%
Piping, Valves, Support, Accessories	$0	$1,130,290	$937,234	17,455	0	$2,067,524	3.1%
Mechanical Insulation & Lagging	$0	$130,818	$81,785	1,506	0	$212,604	0.3%
Combustion Turbine Generator	$29,175,000	$0	$616,886	11,600	0	$29,791,886	44.4%
Steam Generator	$0	$0	$0	0	0	$0	0.0%
AQCS Equipment	$0	$0	$239,309	4,500	0	$239,309	0.4%
Chimney	$0	$0	$0	0	0	$0	0.0%
BOP Mechanical Equipment	$0	$1,609,111	$110,652	2,014	554,421	$2,274,185	3.4%
Electrical Equipment	$560,000	$983,878	$200,148	4,157	0	$1,744,026	2.6%
Electrical Commodities	$0	$685,410	$438,821	8,751	0	$1,124,231	1.7%
High Voltage Electrical & Substation	$0	$0	$0	0	0	$0	0.0%
High Voltage Transmission	$0	$0	$0	0	0	$0	0.0%
Controls & Instrumentation	$0	$1,847,989	$240,999	5,005	0	$2,088,988	3.1%
Subtotal Direct Costs:	$29,735,000	$9,627,801	$3,578,148	71,037	$790,421	$43,731,369	65.2%
Sales Tax	0	0			0	$0	0.0%
Total Direct Cost	$29,735,000	$9,627,801	$3,578,148	71,037	$790,421	$43,731,369	65.2%
Construction Indirects & Services							
- Construction Equipment					$3,068,630	$3,068,630	4.6%
- Construction Field Staff (Construction Mgmt.)					$2,181,589	$2,181,589	3.3%
- Construction Field Staff Expenses					$492,253	$492,253	0.7%
- Construction Permits					$59,906	$59,906	0.1%
- Construction Testing					$248,000	$248,000	0.4%
- Performance Testing					$483,199	$483,199	0.7%
- Preop Testing, Start-up					$601,302	$601,302	0.9%
- Consumable Materials & Safety Supplies					$149,178	$149,178	0.2%
- Field Office Expense					$208,646	$208,646	0.3%
- Site Safety					$215,072	$215,072	0.3%
- Small Tools					$646,997	$646,997	1.0%
- Start up Supervision					$38,653	$38,653	0.1%
- Support Craft & Site Services					$623,478	$623,478	0.9%
- Long Haul Shipping					$300,000	$300,000	0.4%
- Temporary Facilities					$300,463	$300,463	0.4%
- Temporary Utilities					$801,040	$801,040	1.2%
Subtotal Construction Indirects & Services		$0	$0	0	$10,418,405	$10,418,405	15.5%
Total Construction Cost	$29,735,000	$9,627,801	$3,578,148	71,037	$11,208,825	$54,149,774	80.7%
Project Indirects							
- Power Plant Design Engineering					$3,498,510	$3,498,510	5.2%
- Project Management (Home Ofc PM & Procurement)					$437,314	$437,314	0.7%
Sub-Total Project Indirects	$0	$0	$0	0	$3,935,823	$3,935,823	
EPCM Insurance & Misc Costs							
- Builders All Risk Insurance					$0	$0	0.0%
- Comprehensive General Liability (CGL) Insurance					$0	$0	0.0%
- Warranty Reserve					$0	$0	0.0%
Sub-Total EPCM Insurance & Misc. Costs	$0	$0	$0	0	$0	$0	
Total EPCM Project Indirect Cost	$0	$0	$0	0	$3,935,823	$3,935,823	5.9%
Sub-Total	$29,735,000	$9,627,801	$3,578,148	71,037	$15,144,649	$58,085,597	86.6%
- Escalation (Equip, Matls. & Labor)	$0	$0	$0		$0	$0	0.0%
Sub-Total	$29,735,000	$9,627,801	$3,578,148	71,037	$15,144,649	$58,085,597	86.6%
- EPCM Contingency	$931,250	$962,780	$357,815		$1,514,465	$3,766,310	5.6%
- EPCM G&A					$1,742,568	$1,742,568	2.6%
- EPCM Fee					$3,485,136	$3,485,136	5.2%
TOTAL EPCM Project Cost	$30,666,250	$10,590,581	$3,935,963	71,037	$21,886,817	$67,079,611	100.0%
EPC Price per kW						$1,334	

Owners Cost							
- Gas Supply Line					$0	$0	0.0%
TOTAL EPCM Project Cost (w/Owners	$30,666,250	$10,590,581	$3,935,963	71,037	$21,886,817	$67,079,611	100.0%
EPC Price per kW (w/Owner's Cost)						$1,334	

Total Craft Labor Hours	71,037	**Senior Project Manager:**	
Average Craft $/Labor Hour w/o Escalation	$50.37	**Project Manager:**	R.W. Nagel
Field Labor Type	Open Shop	**Construction Lead:**	
Labor Productivity Factor	1.00	**Chief Estimator:**	D.D. Gayeski

Simple Cycle 1x0 CT - 50 MW Aeroderivative Dual Fuel (NG/LNG)

Print Date: 4/9/2018

LOCATION:	2018 IRP
HDR PROJECT #	10103432
PLANT TYPE:	Simple Cycle
CLIENT:	NorthWestern Energy
ESTIMATE TYPE:	Conceptual
LEAD ESTIMATOR:	DDG

60.0

STATUS DATE: 06-Apr-18

COST DATE BASIS: April 2018	BID DUE DATE:	TECHNOLOGY: Gas Turbine	
	LNTP Const. MOB:	NET MW RATING: 50	BOILER: NA
	FNTP:	NET MW ECAR:	STEAM TURBINE: NA
ESCALATION BASIS (APR):	COMMERCIAL OP. DATE:	FUEL TYPE: Natural Gas/LNG	COOLING TYPE: Fin Fan

	TOTAL COSTS						
DIVISION OF WORK	Procurement Major Equipment	Contractor Material $	Contractor Labor $	Contractor Labor Hours	Subcontractor or Other $	Project Total $	%
Demolition & Sitework	$0	$678,927	$159,547	3,754	0	$838,474	1.0%
Deep Foundations & Concrete	$0	$650,462	$336,438	7,931	0	$986,899	1.2%
Architectural & Metals	$0	$2,644,526	$171,927	3,363	0	$2,816,453	3.5%
Piping, Valves, Support, Accessories	$0	$1,007,138	$782,243	14,568	0	$1,789,381	2.2%
Mechanical Insulation & Lagging	$0	$61,243	$61,748	1,133	0	$122,991	0.2%
Combustion Turbine Generator	$25,344,000	$0	$616,886	11,600	0	$25,960,886	31.8%
Steam Generator	$0	$0	$0	0	0	$0	0.0%
AQCS Equipment	$0	$0	$239,309	4,500	0	$239,309	0.3%
Chimney	$0	$0	$0	0	0	$0	0.0%
BOP Mechanical Equipment	$11,996,367	$1,332,111	$166,925	3,062	2,601,581	$16,096,985	19.7%
Electrical Equipment	$560,000	$1,653,088	$189,719	3,940	0	$2,402,807	2.9%
Electrical Commodities	$0	$678,092	$430,455	8,583	0	$1,108,547	1.4%
High Voltage Electrical & Substation	$0	$0	$0	0	0	$0	0.0%
High Voltage Transmission	$0	$0	$0	0	0	$0	0.0%
Controls & Instrumentation	$0	$2,084,877	$255,798	5,313	0	$2,340,675	2.9%
Subtotal Direct Costs:	$37,900,367	$10,790,465	$3,410,994	67,748	$2,601,581	$54,703,406	67.1%
Sales Tax	0	0			0	$0	0.0%
Total Direct Cost	$37,900,367	$10,790,465	$3,410,994	67,748	$2,601,581	$54,703,406	67.1%
Construction Indirects & Services							
- Construction Equipment					$3,068,630	$3,068,630	3.8%
- Construction Field Staff (Construction Mgmt.)					$2,181,589	$2,181,589	2.7%
- Construction Field Staff Expenses					$492,253	$492,253	0.6%
- Construction Permits					$59,906	$59,906	0.1%
- Construction Testing					$248,000	$248,000	0.3%
- Performance Testing					$483,199	$483,199	0.6%
- Preop Testing, Start-up					$601,302	$601,302	0.7%
- Consumable Materials & Safety Supplies					$142,270	$142,270	0.2%
- Field Office Expense					$208,646	$208,646	0.3%
- Site Safety					$215,072	$215,072	0.3%
- Small Tools					$646,997	$646,997	0.8%
- Start up Supervision					$38,653	$38,653	0.0%
- Support Craft & Site Services					$623,478	$623,478	0.8%
- Long Haul Shipping					$300,000	$300,000	0.4%
- Temporary Facilities					$300,463	$300,463	0.4%
- Temporary Utilities					$801,040	$801,040	1.0%
Subtotal Construction Indirects & Services		$0	$0	0	$10,411,497	$10,411,497	12.8%
Total Construction Cost	$37,900,367	$10,790,465	$3,410,994	67,748	$13,013,077	$65,114,903	79.8%
Project Indirects							
- Power Plant Design Engineering					$4,376,272	$4,376,272	5.4%
- Project Management (Home Ofc PM & Procurement)					$547,034	$547,034	0.7%
Sub-Total Project Indirects	$0	$0	$0	0	$4,923,307	$4,923,307	
EPCM Insurance & Misc Costs							
- Builders All Risk Insurance					$0	$0	0.0%
- Comprehensive General Liability (CGL) Insurance					$0	$0	0.0%
- Warranty Reserve					$0	$0	0.0%
Sub-Total EPCM Insurance & Misc. Costs	$0	$0	$0	0	$0	$0	
Total EPCM Project Indirect Cost	$0	$0	$0	0	$4,923,307	$4,923,307	6.0%
Sub-Total	$37,900,367	$10,790,465	$3,410,994	67,748	$17,936,384	$70,038,210	85.9%
- Escalation (Equip, Matls. & Labor)	$0	$0	$0		$0	$0	0.0%
Sub-Total	$37,900,367	$10,790,465	$3,410,994	67,748	$17,936,384	$70,038,210	85.9%
- EPCM Contingency	$2,015,957	$1,079,046	$341,099		$1,793,638	$5,229,741	6.4%
- EPCM G&A					$2,101,146	$2,101,146	2.6%
- EPCM Fee					$4,202,293	$4,202,293	5.2%
TOTAL EPCM Project Cost	$39,916,324	$11,869,511	$3,752,093	67,748	$26,033,461	$81,571,389	100.0%
EPC Price per kW						$1,622	

Owners Cost							
- Gas Supply Line					$0	$0	0.0%
TOTAL EPCM Project Cost (w/Owners	$39,916,324	$11,869,511	$3,752,093	67,748	$26,033,461	$81,571,389	100.0%
EPC Price per kW (w/Owner's Cost)						$1,622	

Total Craft Labor Hours	67,748	Senior Project Manager:	
Average Craft $/Labor Hour w/o Escalation	$50.35	Project Manager:	R.W. Nagel
Field Labor Type	Open Shop	Construction Lead:	
Labor Productivity Factor	1.00	Chief Estimator:	D.D. Gayeski

Combined Cycle 2x1 CT - Frame CT, No Duct Firing

[redacted]

LOCATION: 2018 IRP
HDR PROJECT # 10103432
PLANT TYPE: Combined Cycle
CLIENT: Northwestern Energy
ESTIMATE TYPE: Conceptual
LEAD ESTIMATOR: DDG

STATUS DATE: 30-Mar-18

Cost Basis: March 2018	BID DUE DATE:	TECHNOLOGY:
	LNTP Const. MOB:	NET MW RATING: 139
	FNTP:	NET MW ECAR:
	COMMERCIAL OP. DATE:	FUEL TYPE: gas

BOILER:	HRSG (Unfired)
STEAM TURBINE:	Condensing
COOLING TYPE:	CT w/ Dry Condenser

	TOTAL COSTS					
DIVISION OF WORK	**Procurement Major Equipment**	**Contractor Material $**	**Contractor Labor $**	**Contractor Labor Hours**	**Subcontractor or Other $**	**Project Total $**
Demolition & Sitework	$0	$3,417,246	$2,016,010	45,681	1,072,050	$6,505,306
Deep Foundations & Concrete	$0	$1,114,829	$841,609	19,840	0	$1,956,439
Architectural & Metals	$0	$3,279,553	$1,018,405	19,621	1,041,657	$5,339,615
Piping, Valves, Support, Accessories	$0	$2,955,010	$3,454,250	64,331	170,625	$6,579,886
Mechanical Insulation & Lagging	$0	$188,615	$228,560	4,280	0	$417,175
Combustion Turbine Generator	$40,267,902	$0	$989,144	18,600	0	$41,257,046
HRSG	$14,332,500	$0	$1,342,383	25,000	0	$15,674,883
Steam Turbine Generator	$5,775,000	$0	$165,929	2,500	0	$5,940,929
Air Cooled Condenser	$5,000,000	$0	$0	0	1,500,000	$6,500,000
BOP Mechanical Equipment	$0	$5,916,167	$626,810	11,675	2,898,552	$9,441,530
Electrical Equipment	$3,055,500	$3,048,841	$350,847	7,287	0	$6,455,188
Electrical Commodities	$0	$1,545,938	$1,084,974	22,589	0	$2,630,912
High Voltage Electrical & Substation	$0	$0	$0	0	0	$0
Controls & Instrumentation	$0	$4,996,215	$531,701	11,725	0	$5,527,916
Subtotal Direct Costs:	$68,430,902	$26,462,415	$12,650,625	253,127	$6,682,884	$114,226,825
Sales Tax		0			0	$0
Total Direct Cost	**$68,430,902**	**$26,462,415**	**$12,650,625**	**253,127**	**$6,682,884**	**$114,226,825**
Construction Indirects & Services						
- Construction Equipment					$5,203,525	$5,203,525
- Construction Field Staff (Construction Mgmt.)					$5,852,511	$5,852,511
- Construction Field Staff Expenses					$1,234,630	$1,234,630
- Construction Permits					$8,000	$8,000
- Construction Testing					$408,833	$408,833
- Performance Testing					$317,800	$317,800
- Preop Testing, Start-up					$516,859	$516,859
- Consumable Materials & Safety Supplies					$506,255	$506,255
- Field Office Expense					$325,377	$325,377
- Site Safety					$261,817	$261,817
- Small Tools					$658,939	$658,939
- Start up Supervision					$38,653	$38,653
- Support Craft & Site Services					$827,861	$827,861
- Long Haul Shipping					$340,000	$340,000
- Temporary Facilities					$323,282	$323,282
- Temporary Utilities					$1,038,394	$1,038,394
Subtotal Construction Indirects & Services		$0	$0	0	$17,862,736	$17,862,736
Total Construction Cost	**$68,430,902**	**$26,462,415**	**$12,650,625**	**253,127**	**$24,545,620**	**$132,089,561**
Project Indirects						
- Power Plant Design Engineering					$9,138,146	$9,138,146
- Engineering Management (Home Off PM & Procurement)					$1,142,268	$1,142,268
Sub-Total Project Indirects	$0	$0	$0	0	$10,280,414	$10,280,414
Sub-Total	$68,430,902	$26,462,415	$12,650,625	253,127	$34,826,034	$142,369,975
- EPC Contingency	$4,024,337	$2,646,241	$1,265,062		$3,482,603	$11,418,244
- EPC G&A and Fee					$14,236,998	$14,236,998
TOTAL EPC Project Cost (w/o Ow	**$72,455,239**	**$29,108,656**	**$13,915,687**	**253,127**	**$52,545,635**	**$168,025,217**
EPC Price per kW						$1,209

Total Craft Labor Hours	253,127	Senior Project Manager:	
Average Craft $/Labor Hour w/o Esca	$49.98	Project Manager:	R. Nagel
Field Labor Type	Union	Construction Lead:	
Labor Productivity Factor	1.00	Chief Estimator:	D. Gayeski

Combined Cycle 2x1 CT - Frame CT, with Duct Firing

LOCATION:	2019 IRP
HDR PROJECT #	10103432
PLANT TYPE:	Combined Cycle
CLIENT:	Northwestern Energy
ESTIMATE TYPE:	Conceptual
LEAD ESTIMATOR:	DDG

STATUS DATE: 30-Mar-18

Cost Basis: March 2018	BID DUE DATE:	TECHNOLOGY:			Unfired
	LNTP Const. MOB:	NET MW RATING:	156	BOILER:	HRSG
	FNTP:	NET MW ECAR:		STEAM TURBINE:	Condensing
	COMMERCIAL OP. DATE:	FUEL TYPE:	gas	COOLING TYPE:	CT w/ Dry Condenser

DIVISION OF WORK	TOTAL COSTS Procurement Major Equipment	Contractor Material $	Contractor Labor $	Contractor Labor Hours	Subcontractor or Other $	Project Total $
Demolition & Sitework	$0	$3,813,437.51	$2,245,567	50,895	1,072,050	$7,131,054
Deep Foundations & Concrete	$0	$1,208,466	$910,495	21,464	0	$2,118,962
Architectural & Metals	$0	$3,656,317	$1,129,335	21,777	1,153,751	$5,939,404
Piping, Valves, Support, Accessories	$0	$2,908,634	$3,929,155	73,175	204,750	$7,042,539
Mechanical Insulation & Lagging	$0	$188,982	$231,118	4,349	0	$420,100
Combustion Turbine Generator	$41,000,000	$0	$989,144	18,600	0	$41,989,144
HRSG	$15,407,438	$0	$1,342,383	25,000	0	$16,749,820
Steam Turbine Generator	$6,208,125	$0	$165,929	2,500	0	$6,374,054
Air Cooled Condenser	$5,375,000	$0	$0	0	1,612,500	$6,987,500
BOP Mechanical Equipment	$0	$6,116,617	$640,414	11,928	2,898,552	$9,655,584
Electrical Equipment	$3,131,888	$3,088,216	$353,411	7,340	0	$6,573,515
Electrical Commodities	$0	$1,576,383	$1,127,738	23,477	0	$2,704,121
High Voltage Electrical & Substation	$0	$0	$0	0	0	$0
Controls & Instrumentation	$0	$5,151,668	$534,626	11,790	0	$5,686,293
Subtotal Direct Costs:	$71,122,450	$27,708,720	$13,599,317	272,295	$6,941,604	$119,372,091
Sales Tax		0			0	$0
Total Direct Cost	**$71,122,450**	**$27,708,720**	**$13,599,317**	**272,295**	**$6,941,604**	**$119,372,091**
Construction Indirects & Services						
- Construction Equipment					$5,680,447	$5,680,447
- Construction Field Staff (Construction Mgmt.)					$6,104,598	$6,104,598
- Construction Field Staff Expenses					$1,287,445	$1,287,445
- Construction Permits					$8,000	$8,000
- Construction Testing					$413,667	$413,667
- Performance Testing					$317,800	$317,800
- Preop Testing, Start-up					$516,859	$516,859
- Consumable Materials & Safety Supplies					$544,591	$544,591
- Field Office Expense					$333,422	$333,422
- Site Safety					$266,612	$266,612
- Small Tools					$660,133	$660,133
- Start up Supervision					$38,653	$38,653
- Support Craft & Site Services					$848,300	$848,300
- Long Haul Shipping					$340,000	$340,000
- Temporary Facilities					$325,564	$325,564
- Temporary Utilities					$1,058,995	$1,058,995
Subtotal Construction Indirects & Services		$0	$0	0	$18,745,086	$18,745,086
Total Construction Cost	**$71,122,450**	**$27,708,720**	**$13,599,317**	**272,295**	**$25,686,690**	**$138,117,177**
Project Indirects						
- Power Plant Design Engineering					$9,549,767	$9,549,767
- Engineering Management (Home Off PM & Procurement)					$1,193,721	$1,193,721
Sub-Total Project Indirects	$0	$0	$0	0	$10,743,488	$10,743,488
Sub-Total	$71,122,450	$27,708,720	$13,599,317	272,295	$36,430,178	$148,860,665
- EPC Contingency	$4,242,245	$2,770,872	$1,359,932		$3,643,018	$12,016,067
- EPC G&A and Fee					$14,886,067	$14,886,067
TOTAL EPC Project Cost (w/o Ov	**$75,364,695**	**$30,479,592**	**$14,959,249**	**272,295**	**$54,959,262**	**$175,762,799**
EPC Price per kW						$1,127

Total Craft Labor Hours	272,295	Senior Project Manager:	
Average Craft $/Labor Hour w/o Esca	$49.94	Project Manager:	R. Nagel
Field Labor Type	Union	Construction Lead:	
Labor Productivity Factor	1.00	Chief Estimator:	D. Gayeski

Simple Cycle 1x0 RICE - 18 MW Class

Print Date: 4/9/2018

LOCATION:	2018 IRP
HDR PROJECT #	10103432
PLANT TYPE:	Simple Cycle
CLIENT:	NorthWestern Energy
ESTIMATE TYPE:	Conceptual
LEAD ESTIMATOR:	DDG

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STATUS DATE: 06-Apr-18

COST DATE BASIS: March 2016	BID DUE DATE:		TECHNOLOGY:	Engine Generator	
	LNTP Const. MOB:		NET MW RATING (AVG):	18	BOILER: NA
	FNTP:		NET MW ECAR:		STEAM TURBINE: NA
ESCALATION BASIS (APR):	COMMERCIAL OP. DATE:	Jan-2019	FUEL TYPE:	Natural Gas	COOLING TYPE:

	TOTAL COSTS						
DIVISION OF WORK	Procurement Major Equipment	Contractor Material $	Contractor Labor $	Contractor Labor Hours	Subcontractor or Other $	Project Total $	%
Demolition & Sitework	$0	$246,286	$113,392	2,669	0	$359,678	1.1%
Deep Foundations & Concrete	$0	$231,516	$175,827	4,145	0	$407,343	1.2%
Architectural & Metals	$0	$1,973,516	$152,637	3,052	0	$2,126,154	6.3%
Piping, Valves, Support, Accessories	$0	$997,190	$553,570	10,309	0	$1,550,760	4.6%
Mechanical Insulation & Lagging	$0	$58,534	$57,601	1,055	0	$116,135	0.3%
Natural Gas Generator Set	$10,306,500	$0	$149,754	2,816	0	$10,456,254	30.8%
AQCS Equipment (Included in Gen Set Above	$0	$0	$0	0	0	$0	0.0%
Stack	$120,000	$0	$42,544	800		$162,544	0.5%
BOP Mechanical Equipment	$217,588	$643,245	$368,741	6,871	69,447	$1,299,021	3.8%
Electrical Equipment	$813,895	$117,788	$84,524	1,755	0	$1,016,206	3.0%
Electrical Commodities	$0	$506,151	$269,300	5,426	0	$775,451	2.3%
High Voltage Electrical & Substation	$0	$0	$0	0	0	$0	0.0%
High Voltage Transmission	$0	$0	$0	0	0	$0	0.0%
Controls & Instrumentation	$0	$687,209	$119,526	2,482	0	$806,735	2.4%
Subtotal Direct Costs:	$11,457,983	$5,461,436	$2,087,416	41,382	$69,447	$19,076,282	56.3%
Sales Tax	0	0			0	$0	0.0%
Total Direct Cost	$11,457,983	$5,461,436	$2,087,416	41,382	$69,447	$19,076,282	56.3%
Construction Indirects & Services							
- Construction Equipment					$2,717,696	$2,717,696	8.0%
- Construction Field Staff (Construction Mgmt.)					$2,024,997	$2,024,997	6.0%
- Construction Field Staff Expenses					$397,825	$397,825	1.2%
- Construction Permits					$39,250	$39,250	0.1%
- Construction Testing					$31,042	$31,042	0.1%
- Performance Testing					$317,800	$317,800	0.9%
- Preop Testing, Start-up					$451,859	$451,859	1.3%
- Consumable Materials & Safety Supplies					$86,903	$86,903	0.3%
- Field Office Expense					$161,154	$161,154	0.5%
- Site Safety					$161,606	$161,606	0.5%
- Small Tools					$86,903	$86,903	0.3%
- Start up Supervision					$39,162	$39,162	0.1%
- Support Craft & Site Services					$439,291	$439,291	1.3%
- Long Haul Shipping					$0	$0	0.0%
- Temporary Facilities					$295,899	$295,899	0.9%
- Temporary Utilities					$602,003	$602,003	1.8%
Subtotal Construction Indirects & Services		$0	$0	0	$7,853,391	$7,853,391	23.2%
Total Construction Cost	$11,457,983	$5,461,436	$2,087,416	41,382	$7,922,838	$26,929,673	79.4%
Project Indirects							
- Power Plant Design Engineering					$1,526,103	$1,526,103	4.5%
- Project Management (Home Ofc PM & Procurement)					$269,297	$269,297	0.8%
Sub-Total Project Indirects	$0	$0	$0	0	$1,795,399	$1,795,399	
EPC Insurance & Misc Costs							
- Builders All Risk Insurance					$0	$0	0.0%
- Comprehensive General Liability (CGL) Insurance					$0	$0	0.0%
- Warranty Reserve					$0	$0	0.0%
Sub-Total EPC Insurance & Misc. Costs	$0	$0	$0	0	$0	$0	
Total EPC Project Indirect Cost	$0	$0	$0	0	$1,795,399	$1,795,399	5.3%
Sub-Total	$11,457,983	$5,461,436	$2,087,416	41,382	$9,718,237	$28,725,072	84.7%
- Escalation (Equip, Matls. & Labor)	$0	$0	$0		$0	$0	0.0%
Sub-Total	$11,457,983	$5,461,436	$2,087,416	41,382	$9,718,237	$28,725,072	84.7%
- EPC Contingency	$916,639	$436,915	$166,993		$777,459	$2,298,006	6.8%
- EPC G&A and Fee	$1,145,798	$546,144	$208,742		$971,824	$2,872,507	8.5%
TOTAL EPC Project Cost	$13,520,420	$6,444,495	$2,463,151	41,382	$11,467,520	$33,895,585	100.0%
EPC Price per kW						$1,883	

Simple Cycle 1x0 RICE - 18 MW Class Dual Fuel (NG/FO)

LOCATION:	2018 IRP
HDR PROJECT #	10072178
PLANT TYPE:	Simple Cycle
CLIENT:	NorthWestern Energy
ESTIMATE TYPE:	Conceptual
LEAD ESTIMATOR:	DDG

STATUS DATE: 26-Mar-18

COST DATE BASIS: March 2018	BID DUE DATE:	TECHNOLOGY: Engine Generator	
	LNTP Const. MOB:	NET MW RATING (AVG): 18	BOILER: NA
	FNTP:	NET MW ECAR:	STEAM TURBINE: NA
ESCALATION BASIS (APR):	COMMERCIAL OP. DATE:	FUEL TYPE: Fuel Oil/Natural Gas	COOLING TYPE: Fin Fan

	TOTAL COSTS						
DIVISION OF WORK	**Procurement Major Equipment**	**Contractor Material $**	**Contractor Labor $**	**Contractor Labor Hours**	**Subcontractor or Other $**	**Project Total $**	**%**
Demolition & Sitework	$0	$291,802	$122,284	2,656	0	$414,087	1.2%
Deep Foundations & Concrete	$0	$342,600	$305,935	6,715	0	$648,535	1.9%
Architectural & Metals	$0	$1,664,190	$177,777	3,165	0	$1,841,967	5.4%
Piping, Valves, Support, Accessories	$0	$631,382	$879,754	15,248	0	$1,511,135	4.4%
Mechanical Insulation & Lagging	$0	$62,043	$68,360	1,177	0	$130,403	0.4%
Natural Gas Generator Set	$10,811,200	$0	$156,414	2,816	0	$10,967,614	32.0%
AQCS Equipment (Included in Gen Set Above)	$0	$0	$0	0	0	$0	0.0%
Stack	$90,000	$0	$55,545	1,000		$145,545	0.4%
BOP Mechanical Equipment	$275,000	$1,814,150	$308,565	5,355	305,000	$2,702,715	7.9%
Electrical Equipment	$1,058,000	$110,517	$81,906	1,573	60,000	$1,310,424	3.8%
Electrical Commodities	$0	$471,345	$245,421	4,590	0	$716,766	2.1%
High Voltage Electrical & Substation	$0	$0	$0	0	0	$0	0.0%
High Voltage Transmission	$0	$0	$0	0	0	$0	0.0%
Controls & Instrumentation	$0	$880,635	$192,428	3,697	0	$1,073,063	3.1%
Subtotal Direct Costs:	$12,234,200	$6,268,665	$2,594,389	47,991	$365,000	$21,462,254	62.6%
Sales Tax	0	0			0	$0	0.0%
Total Direct Cost	$12,234,200	$6,268,665	$2,594,389	47,991	$365,000	$21,462,254	62.6%
Construction Indirects & Services							
- Construction Equipment					$1,848,713	$1,848,713	5.4%
- Construction Field Staff (Construction Mgmt.)					$673,814	$673,814	2.0%
- Construction Field Staff Expenses					$165,954	$165,954	0.5%
- Construction Permits					$12,260	$12,260	0.0%
- Construction Testing					$21,333	$21,333	0.1%
- Performance Testing					$276,000	$276,000	0.8%
- Preop Testing, Start-up					$375,763	$375,763	1.1%
- Consumable Materials & Safety Supplies					$100,782	$100,782	0.3%
- Field Office Expense					$137,246	$137,246	0.4%
- Site Safety					$141,305	$141,305	0.4%
- Small Tools					$100,782	$100,782	0.3%
- Start up Supervision					$25,643	$25,643	0.1%
- Support Craft & Site Services					$312,250	$312,250	0.9%
- Long Haul Shipping					$0	$0	0.0%
- Temporary Facilities					$201,045	$201,045	0.6%
- Temporary Utilities					$428,272	$428,272	1.2%
Subtotal Construction Indirects & Services		$0	$0	0	$4,821,162	$4,821,162	14.1%
Total Construction Cost	$12,234,200	$6,268,665	$2,594,389	47,991	$5,186,162	$26,283,416	76.6%
Project Indirects							
- Power Plant Design Engineering					$1,716,980	$1,716,980	5.0%
- Project Management (Home Ofc PM & Procurement)					$262,834	$262,834	0.8%
Sub-Total Project Indirects	$0	$0	$0	0	$1,979,814	$1,979,814	
EPC Insurance & Misc Costs							
- Builders All Risk Insurance					$328,543	$328,543	1.0%
- Comprehensive General Liability (CGL) Insurance					$394,251	$394,251	1.1%
- Warranty Reserve					$550,000	$550,000	1.6%
Sub-Total EPC Insurance & Misc. Costs	$0	$0	$0	0	$1,272,794	$1,272,794	
Total EPC Project Indirect Cost	$0	$0	$0	0	$3,252,608	$3,252,608	9.5%
Sub-Total	$12,234,200	$6,268,665	$2,594,389	47,991	$8,438,770	$29,536,024	86.1%
- Escalation (Equip, Matls. & Labor)	$0	$0	$0		$0	$0	0.0%
Sub-Total	$12,234,200	$6,268,665	$2,594,389	47,991	$8,438,770	$29,536,024	86.1%
- EPC Contingency	$438,176	$501,493	$207,551		$675,102	$1,822,322	5.3%
- EPC G&A and Fee	$1,223,420	$626,866	$259,439		$843,877	$2,953,602	8.6%
TOTAL EPC Project Cost	**$13,895,796**	**$7,397,024**	**$3,061,379**	**47,991**	**$9,957,749**	**$34,311,949**	100.0%
EPC Price per kW						$1,906	

Simple Cycle 1x0 RICE - 18 MW Class Dual Fuel (NG/LNG)

Print Date: 4/9/2018

LOCATION:	2018 IRP
HDR PROJECT #	10103432
PLANT TYPE:	Simple Cycle
CLIENT:	NorthWestern Energy
ESTIMATE TYPE:	Conceptual
LEAD ESTIMATOR:	DDG

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STATUS DATE: 06-Apr-18

COST DATE BASIS: March 2016	BID DUE DATE:		TECHNOLOGY:	Engine Generator	
	LNTP Const. MOB:		NET MW RATING (AVG):	18	BOILER: NA
	FNTP:		NET MW ECAR:		STEAM TURBINE: NA
ESCALATION BASIS (APR):	COMMERCIAL OP. DATE:	Jan-2019	FUEL TYPE:	Natural Gas/LNG	COOLING TYPE:

	TOTAL COSTS						
DIVISION OF WORK	Procurement Major Equipment	Contractor Material $	Contractor Labor $	Contractor Labor Hours	Subcontractor or Other $	Project Total $	%
Demolition & Sitework	$0	$418,264	$113,396	2,669	0	$531,661	1.3%
Deep Foundations & Concrete	$0	$334,703	$175,827	4,145	0	$510,530	1.3%
Architectural & Metals	$0	$2,134,029	$152,637	3,052	0	$2,286,667	5.8%
Piping, Valves, Support, Accessories	$0	$998,048	$630,439	11,741	0	$1,628,487	4.1%
Mechanical Insulation & Lagging	$0	$58,534	$57,601	1,055	0	$116,135	0.3%
Natural Gas Generator Set	$10,306,500	$0	$149,754	2,816	0	$10,456,254	26.3%
AQCS Equipment (Included in Gen Set Above	$0	$0	$0	0	0	$0	0.0%
Stack	$120,000	$0	$42,544	800		$162,544	0.4%
BOP Mechanical Equipment	$2,830,511	$643,245	$368,741	6,871	1,231,447	$5,073,944	12.8%
Electrical Equipment	$813,895	$281,511	$84,524	1,755	0	$1,179,930	3.0%
Electrical Commodities	$0	$506,151	$269,300	5,426	0	$775,451	2.0%
High Voltage Electrical & Substation	$0	$0	$0	0	0	$0	0.0%
High Voltage Transmission	$0	$0	$0	0	0	$0	0.0%
Controls & Instrumentation	$0	$760,586	$119,526	2,482	0	$880,113	2.2%
Subtotal Direct Costs:	$14,070,905	$6,135,073	$2,164,290	42,814	$1,231,447	$23,601,715	59.4%
Sales Tax	0	0			0	$0	0.0%
Total Direct Cost	$14,070,905	$6,135,073	$2,164,290	42,814	$1,231,447	$23,601,715	59.4%
Construction Indirects & Services							
- Construction Equipment					$2,717,696	$2,717,696	6.8%
- Construction Field Staff (Construction Mgmt.)					$2,024,997	$2,024,997	5.1%
- Construction Field Staff Expenses					$397,825	$397,825	1.0%
- Construction Permits					$39,250	$39,250	0.1%
- Construction Testing					$31,042	$31,042	0.1%
- Performance Testing					$317,800	$317,800	0.8%
- Preop Testing, Start-up					$451,859	$451,859	1.1%
- Consumable Materials & Safety Supplies					$89,910	$89,910	0.2%
- Field Office Expense					$161,154	$161,154	0.4%
- Site Safety					$161,606	$161,606	0.4%
- Small Tools					$89,910	$89,910	0.2%
- Start up Supervision					$39,162	$39,162	0.1%
- Support Craft & Site Services					$439,291	$439,291	1.1%
- Long Haul Shipping					$0	$0	0.0%
- Temporary Facilities					$295,899	$295,899	0.7%
- Temporary Utilities					$602,003	$602,003	1.5%
Subtotal Construction Indirects & Services		$0	$0	0	$7,859,404	$7,859,404	19.8%
Total Construction Cost	$14,070,905	$6,135,073	$2,164,290	42,814	$9,090,851	$31,461,119	79.2%
Project Indirects							
- Power Plant Design Engineering					$1,888,137	$1,888,137	4.8%
- Project Management (Home Ofc PM & Procurement)					$314,611	$314,611	0.8%
Sub-Total Project Indirects	$0	$0	$0	0	$2,202,748	$2,202,748	
EPC Insurance & Misc Costs							
- Builders All Risk Insurance					$0	$0	0.0%
- Comprehensive General Liability (CGL) Insurance					$0	$0	0.0%
- Warranty Reserve					$0	$0	0.0%
Sub-Total EPC Insurance & Misc. Costs	$0	$0	$0	0	$0	$0	
Total EPC Project Indirect Cost	$0	$0	$0	0	$2,202,748	$2,202,748	5.5%
Sub-Total	$14,070,905	$6,135,073	$2,164,290	42,814	$11,293,599	$33,663,867	84.7%
- Escalation (Equip, Matls. & Labor)	$0	$0	$0		$0	$0	0.0%
Sub-Total	$14,070,905	$6,135,073	$2,164,290	42,814	$11,293,599	$33,663,867	84.7%
- EPC Contingency	$1,125,672	$490,806	$173,143		$903,488	$2,693,109	6.8%
- EPC G&A and Fee	$1,407,091	$613,507	$216,429		$1,129,360	$3,366,387	8.5%
TOTAL EPC Project Cost	$16,603,668	$7,239,387	$2,553,862	42,814	$13,326,447	$39,723,363	100.0%
EPC Price per kW						$2,207	

Simple Cycle 1x0 RICE - 9 MW Class

Print Date: 4/9/2018

LOCATION: 2018 IRP
HDR PROJECT #: 10072178
PLANT TYPE: Simple Cycle
CLIENT: NorthWestern Energy
ESTIMATE TYPE: Conceptual
LEAD ESTIMATOR: DDG

STATUS DATE: 30-Mar-18

COST DATE BASIS: March 2016	BID DUE DATE:	TECHNOLOGY: Engine Generator	
	LNTP Const. MOB:	NET MW RATING (AVG): 10	BOILER: NA
	FNTP:	NET MW ECAR:	STEAM TURBINE: NA
ESCALATION BASIS (APR):	COMMERCIAL OP. DATE: Jan-2019	FUEL TYPE: Natural Gas	COOLING TYPE:

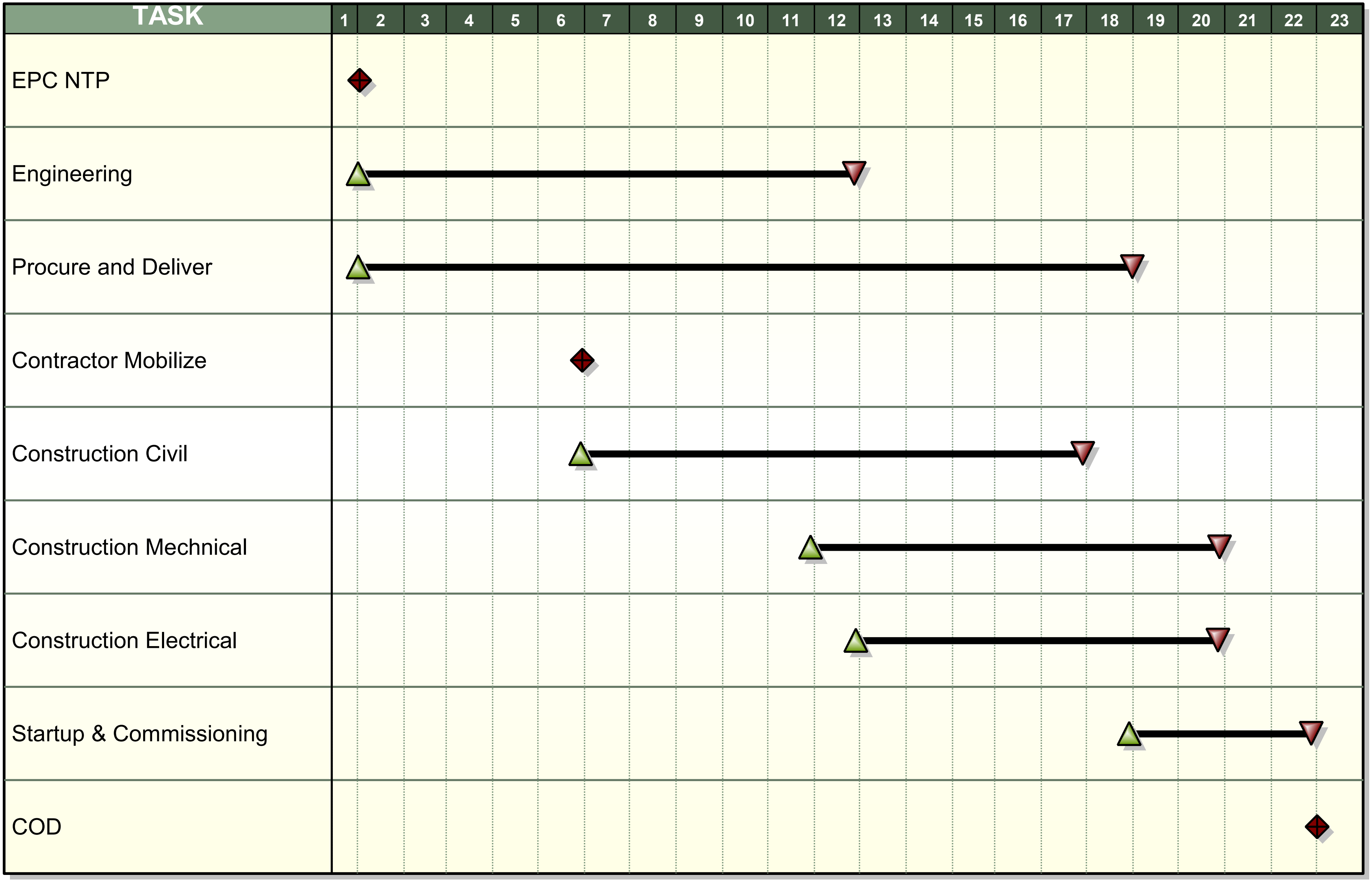
	TOTAL COSTS						
DIVISION OF WORK	Procurement Major Equipment	Contractor Material $	Contractor Labor $	Contractor Labor Hours	Subcontractor or Other $	Project Total $	%
Demolition & Sitework	$0	$179,687	$75,435	1,766	0	$255,122	1.2%
Deep Foundations & Concrete	$0	$140,644	$106,813	2,518	0	$247,457	1.2%
Architectural & Metals	$0	$1,466,612	$109,675	2,182	0	$1,576,287	7.5%
Piping, Valves, Support, Accessories	$0	$937,995	$360,137	6,707	0	$1,298,131	6.1%
Mechanical Insulation & Lagging	$0	$51,801	$46,889	857	0	$98,690	0.5%
Natural Gas Generator Set	$4,962,333	$0	$97,789	1,839	0	$5,060,122	23.9%
AQCS Equipment (Included in Gen Set Above	$0	$0	$0	0	0	$0	0.0%
Stack	$64,441	$0	$22,846	430		$87,287	0.4%
BOP Mechanical Equipment	$132,183	$391,021	$361,251	6,732	42,188	$926,642	4.4%
Electrical Equipment	$570,574	$107,784	$69,411	1,442	0	$747,769	3.5%
Electrical Commodities	$0	$425,925	$196,028	3,970	0	$621,953	2.9%
High Voltage Electrical & Substation	$0	$0	$0	0	0	$0	0.0%
High Voltage Transmission	$0	$0	$0	0	0	$0	0.0%
Controls & Instrumentation	$0	$483,856	$73,764	1,532	0	$557,620	2.6%
Subtotal Direct Costs:	$5,729,531	$4,185,323	$1,520,038	29,973	$42,188	$11,477,081	54.2%
Sales Tax	0	0			0	$0	0.0%
Total Direct Cost	$5,729,531	$4,185,323	$1,520,038	29,973	$42,188	$11,477,081	54.2%
Construction Indirects & Services							
- Construction Equipment					$2,123,927	$2,123,927	10.0%
- Construction Field Staff (Construction Mgmt.)					$629,499	$629,499	3.0%
- Construction Field Staff Expenses					$119,561	$119,561	0.6%
- Construction Permits					$39,025	$39,025	0.2%
- Construction Testing					$22,479	$22,479	0.1%
- Performance Testing					$317,800	$317,800	1.5%
- Preop Testing, Start-up					$451,859	$451,859	2.1%
- Consumable Materials & Safety Supplies					$62,943	$62,943	0.3%
- Field Office Expense					$144,219	$144,219	0.7%
- Site Safety					$147,220	$147,220	0.7%
- Small Tools					$62,943	$62,943	0.3%
- Start up Supervision					$30,887	$30,887	0.1%
- Support Craft & Site Services					$384,108	$384,108	1.8%
- Long Haul Shipping					$0	$0	0.0%
- Temporary Facilities					$289,054	$289,054	1.4%
- Temporary Utilities					$540,198	$540,198	2.6%
Subtotal Construction Indirects & Services		$0	$0	0	$5,365,721	$5,365,721	25.4%
Total Construction Cost	$5,729,531	$4,185,323	$1,520,038	29,973	$5,407,910	$16,842,802	79.6%
Project Indirects							
- Power Plant Design Engineering					$918,166	$918,166	4.3%
- Project Management (Home Ofc PM & Procurement)					$168,428	$168,428	0.8%
Sub-Total Project Indirects	$0	$0	$0	0	$1,086,594	$1,086,594	
EPC Insurance & Misc Costs							
- Builders All Risk Insurance					$0	$0	0.0%
- Comprehensive General Liability (CGL) Insurance					$0	$0	0.0%
- Warranty Reserve					$0	$0	0.0%
Sub-Total EPC Insurance & Misc. Costs	$0	$0	$0	0	$0	$0	
Total EPC Project Indirect Cost	$0	$0	$0	0	$1,086,594	$1,086,594	5.1%
Sub-Total	$5,729,531	$4,185,323	$1,520,038	29,973	$6,494,504	$17,929,397	84.7%
- Escalation (Equip, Matls. & Labor)	$0	$0	$0		$0	$0	0.0%
Sub-Total	$5,729,531	$4,185,323	$1,520,038	29,973	$6,494,504	$17,929,397	84.7%
- EPC Contingency	$458,363	$334,826	$121,603		$519,560	$1,434,352	6.8%
- EPC G&A and Fee	$572,953	$418,532	$152,004		$649,450	$1,792,940	8.5%
TOTAL EPC Project Cost	$6,760,847	$4,938,682	$1,793,645	29,973	$7,663,515	$21,156,688	100.0%
EPC Price per kW						$2,116	

Appendix B

Conceptual Project Implementation Schedules

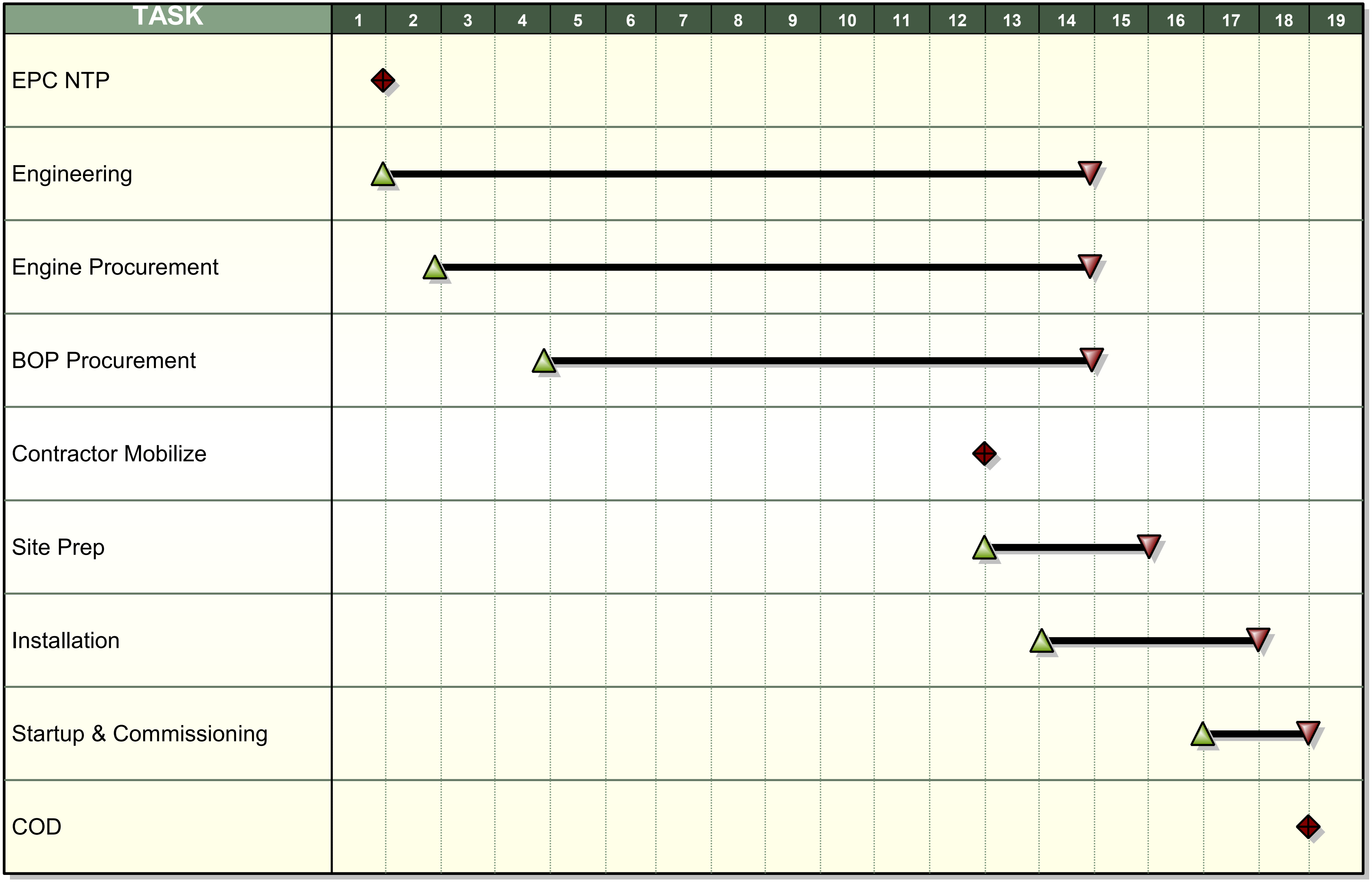
NorthWestern Energy
2018 Resource Plan Support
Simple Cycle CT Conceptual Schedule

4/13/2018



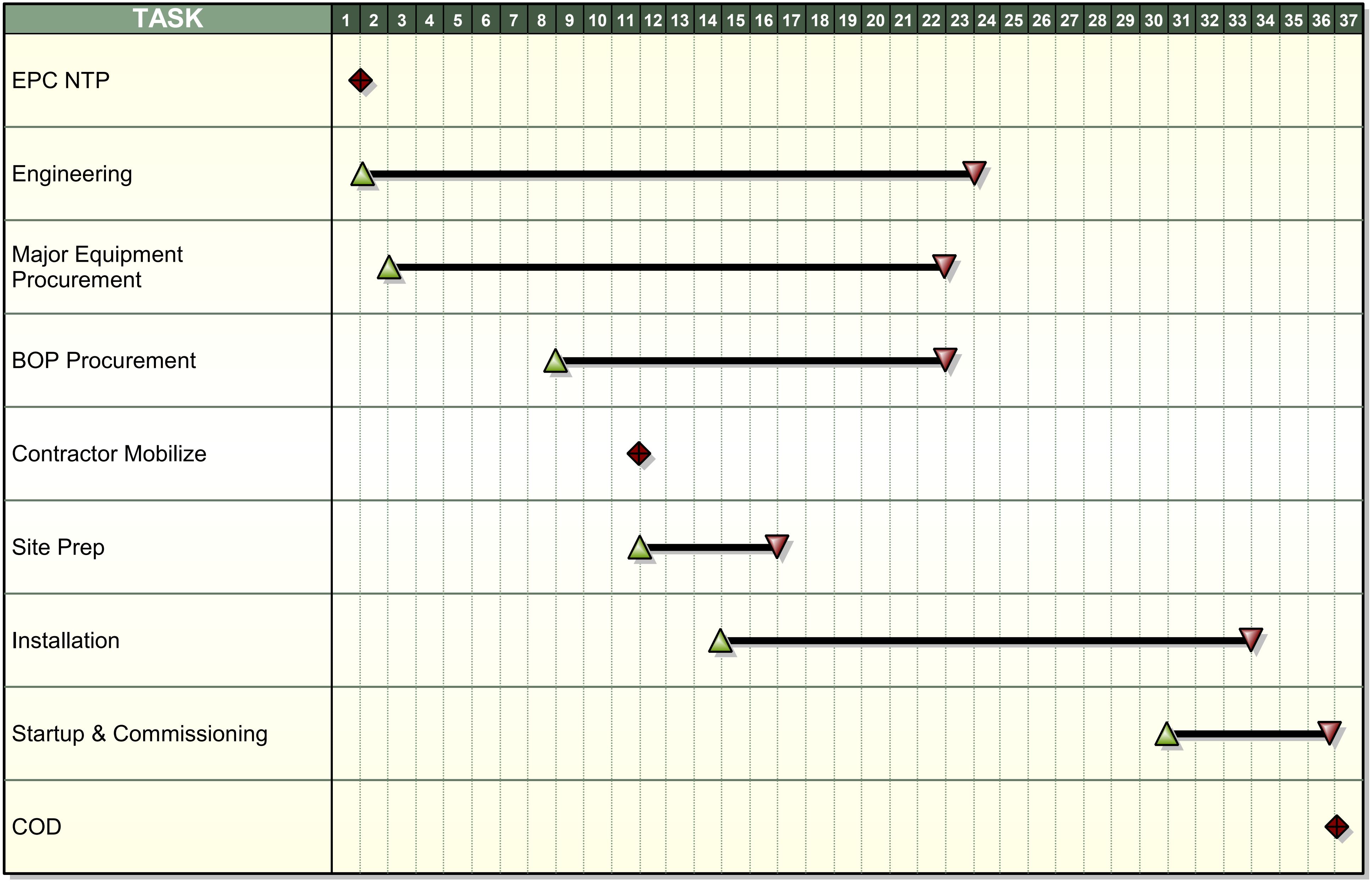
NorthWestern Energy
2018 Resource Plan Support
1x0 Reciprocating Engine Plant

4/13/2018



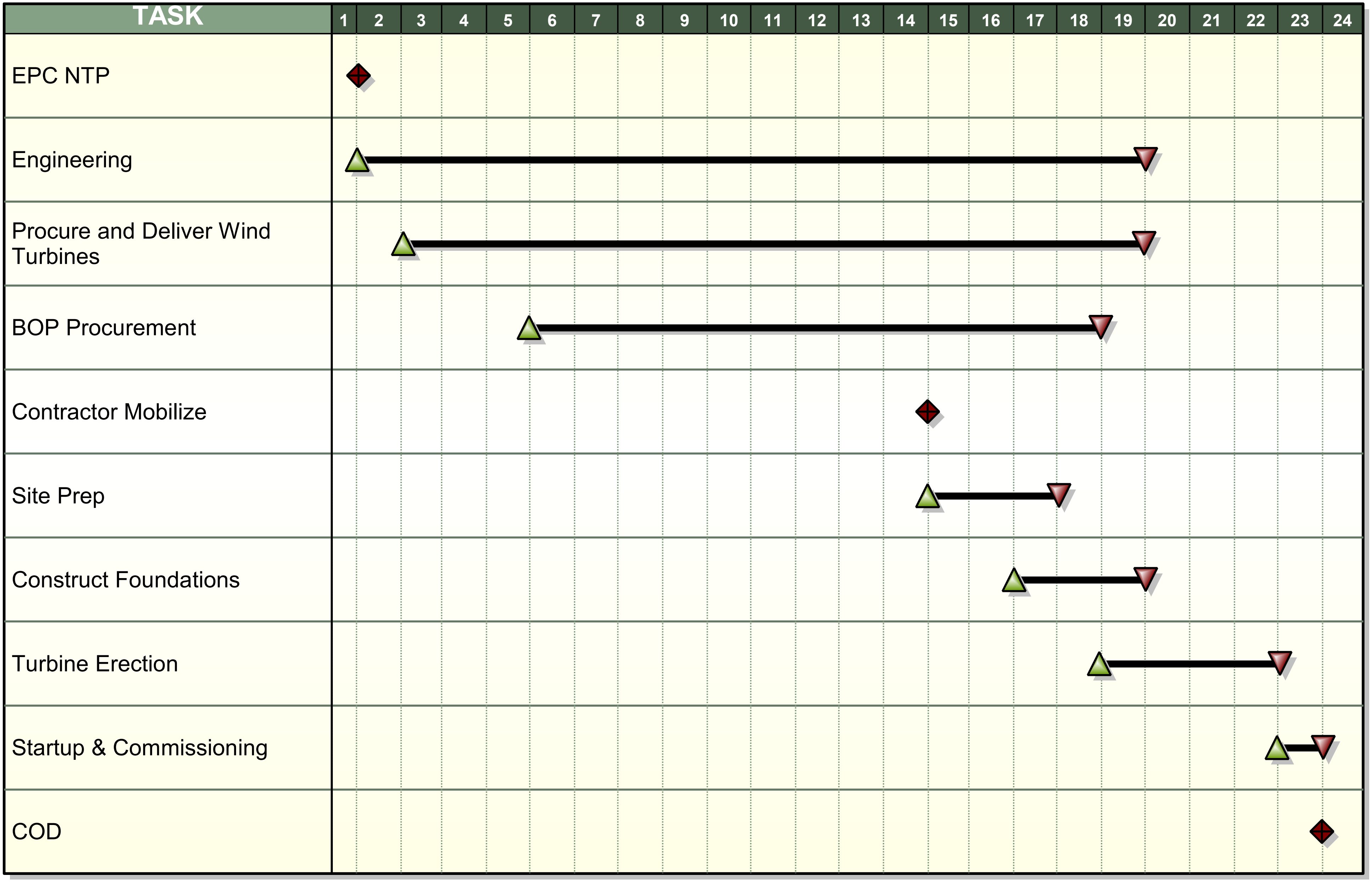
NorthWestern Energy
2018 Resource Plan Support
Combined Cycle CT Conceptual Schedule

4/13/2018



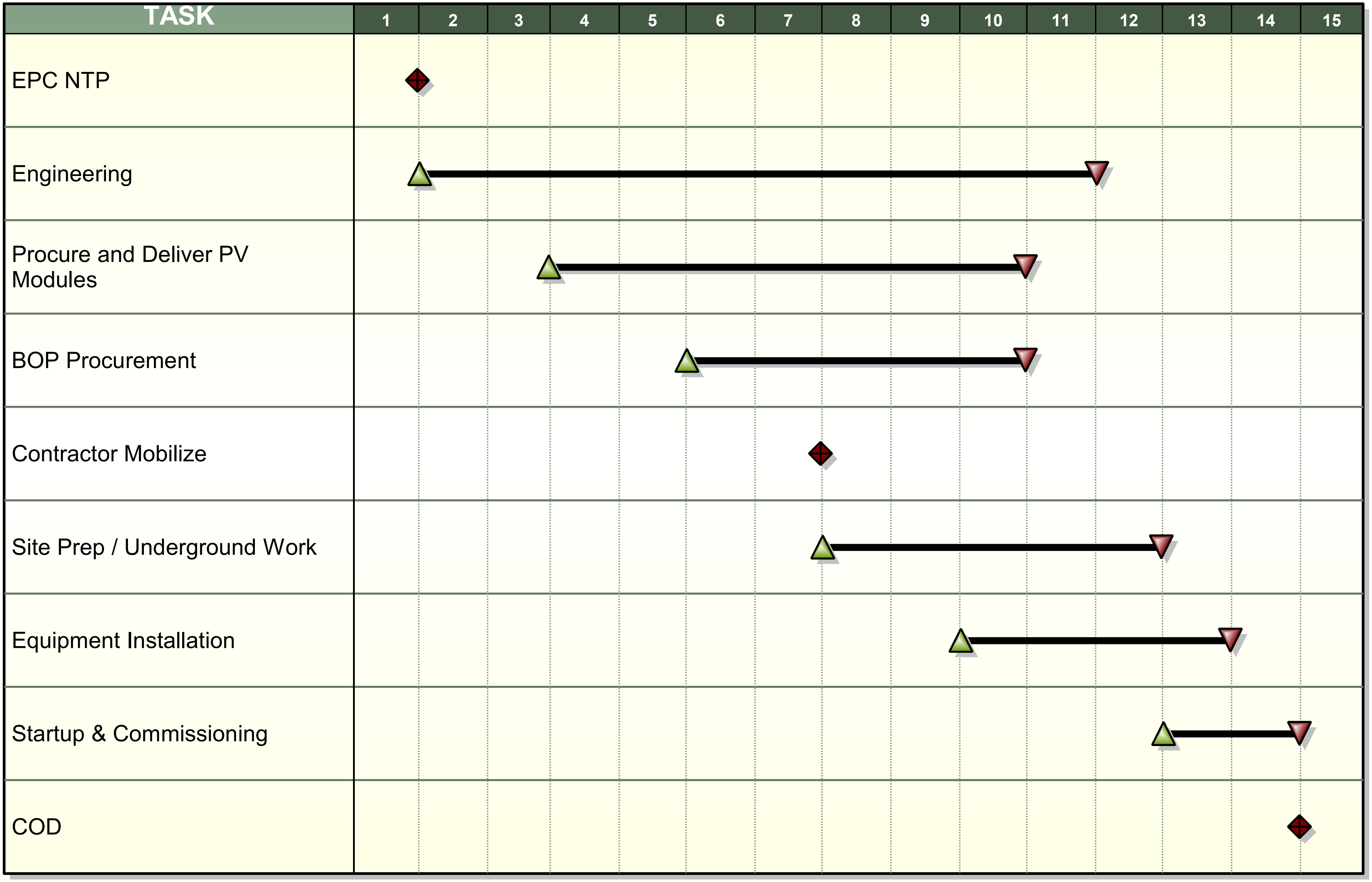
NorthWestern Energy
2018 Resource Plan Support
Wind Farm Conceptual Schedule

4/13/2018



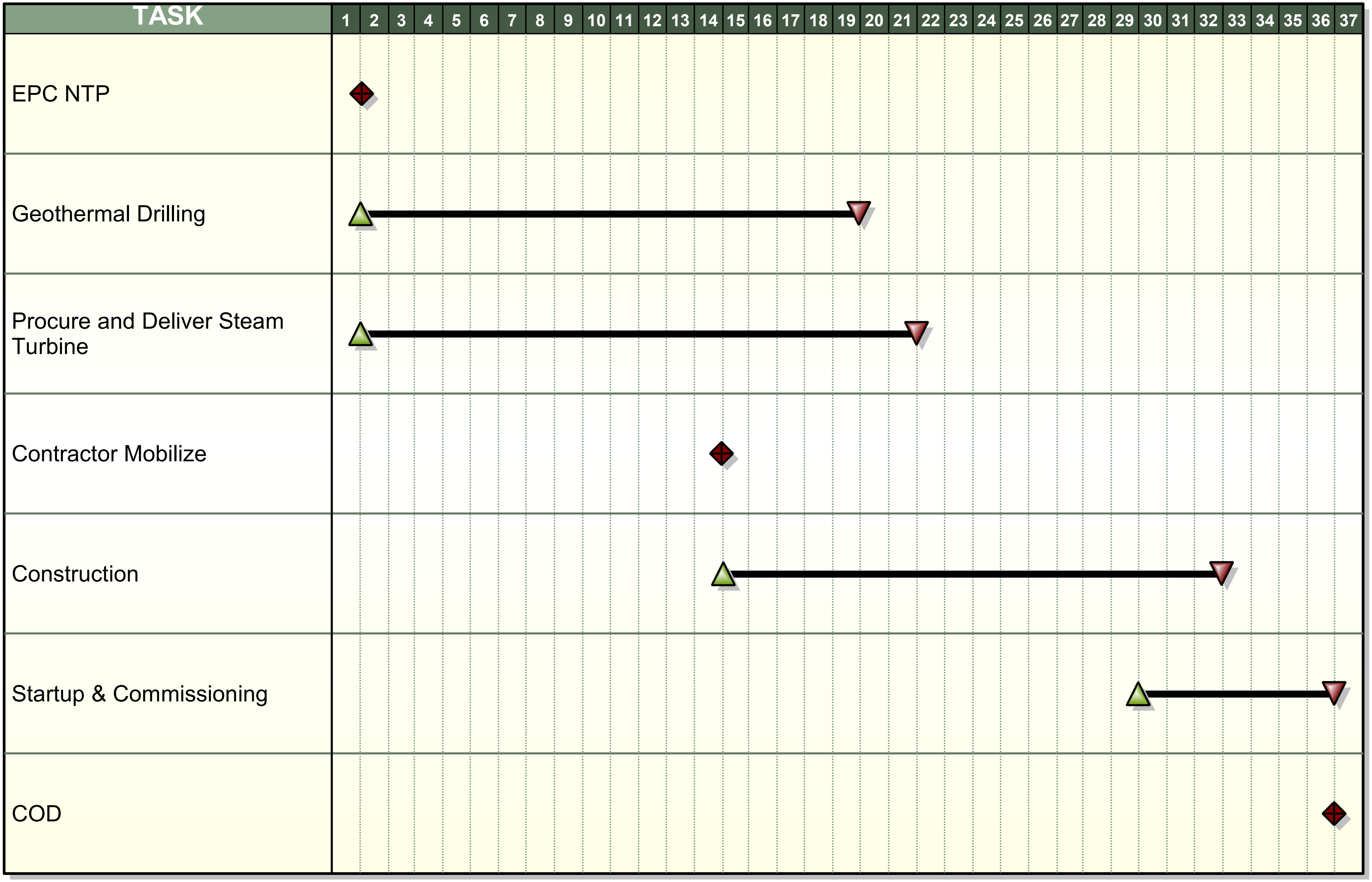
NorthWestern Energy
2018 Resource Plan Support
PV Solar Conceptual Schedule

4/13/2018



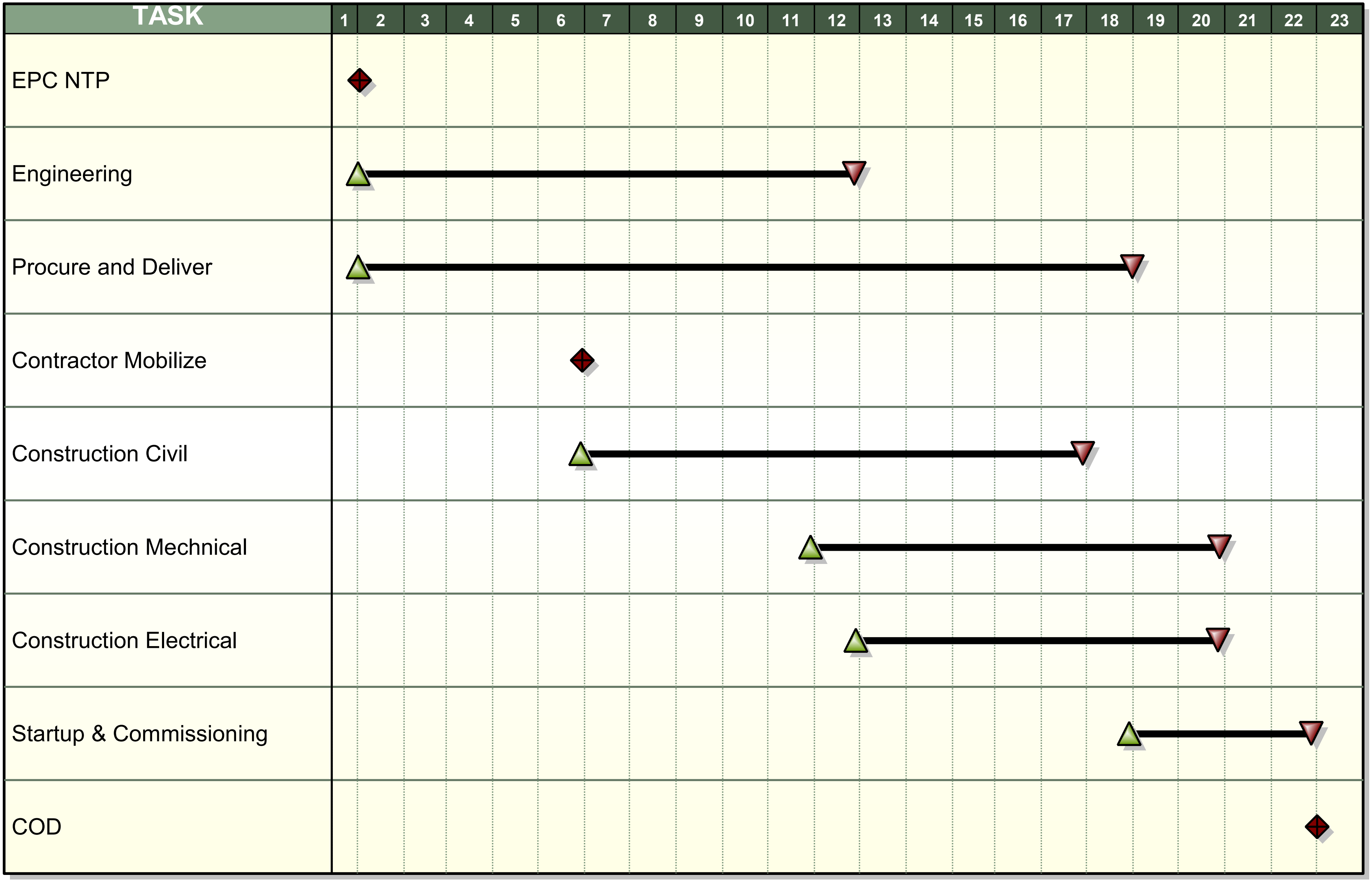
NorthWestern Energy
2018 Resource Plan Support
Geothermal Conceptual Schedule

4/13/2018



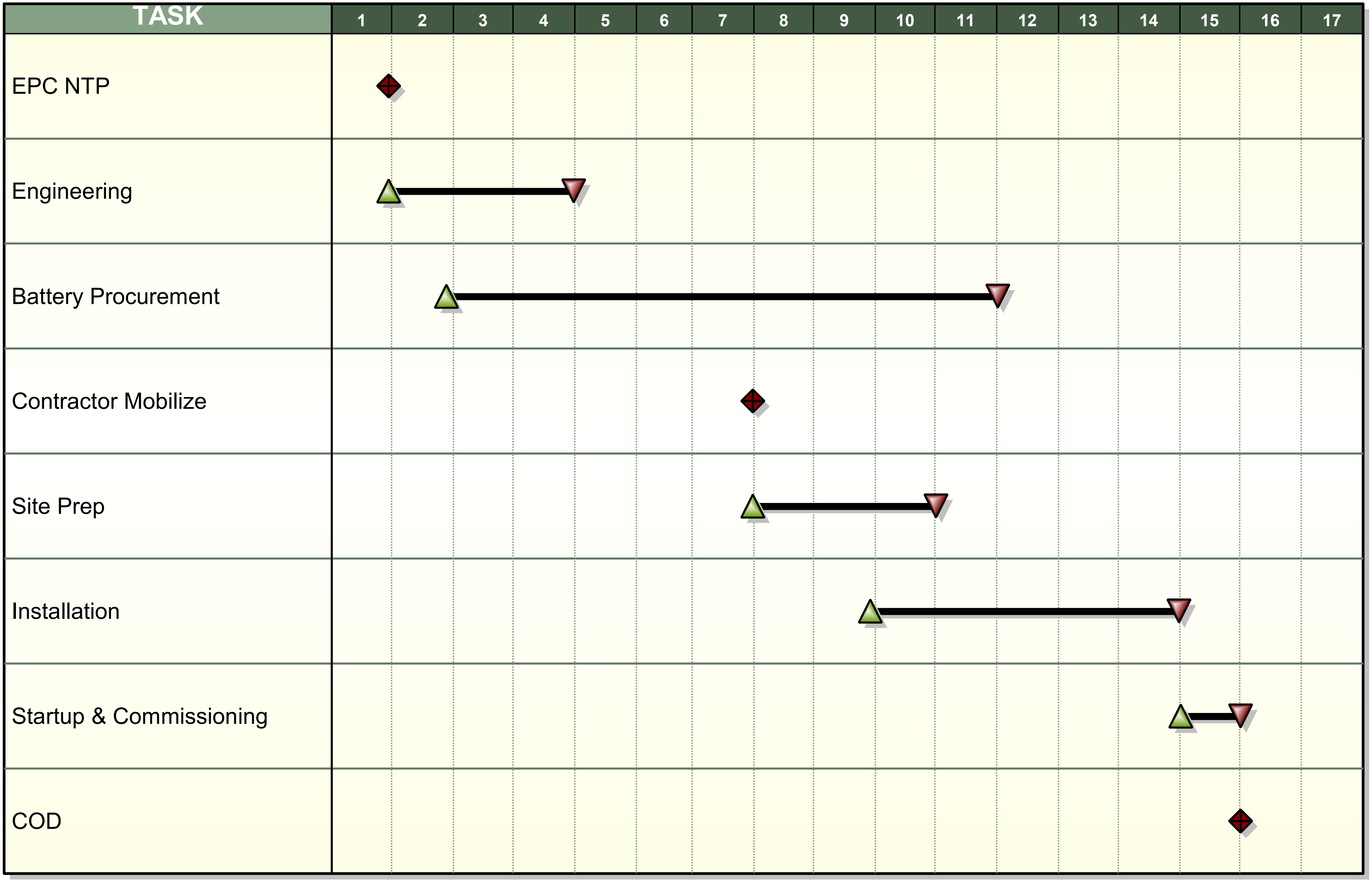
NorthWestern Energy
2018 Resource Plan Support
Compressed Air Conceptual Schedule

4/13/2018



NorthWestern Energy
2018 Resource Plan Support
Battery Plant

4/13/2018



Appendix C

Dispatch Modeling Input Templates

(Native File Format)