IPL Combustion Turbine

Economic Evaluation Report

INDEPENDENCE
• POWER & LIGHT •

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Introduction and Objective

The primary objective of this report is to provide an updated economic evaluation of IPL's Combustion Turbine fleet. This study will consider the combustion turbine evaluation and condition assessment results provided by Burns & McDonnell as part of the 2018 Energy Master Plan Study. Additionally, the updated market cost for replacement capacity that resulted from the 2019 Power Supply RFP will also be included as part of the economic evaluation.

Executive Summary

It is the determination of this report that continuing to operate the six combustion turbines for an operating horizon of 10 years is the lowest cost option that maintains the current level of system reliability. Three paths were considered as part of this analysis:

- Continue Operation of CTs with Recommended Maintenance and CapEx for 10 Years
- Retire all CTs, Upgrade System for N-2 Reliability, Purchase 10-year PPA
- Retire all CTs and Replace with Five Natural Gas Reciprocating Units

The table below represents a comparison of estimated costs over the next 10 operating years.

Cost Estimate to Continue 93 MW of CT Operation for 10 Years

10-Year Total Fixed Costs (Fixed O&M and Capital)	$10,294,383
Labor Cost (Industry Benchmarked)	$38,894,400
Estimated Net Revenue Above the Cost of Fuel	*-$2,315,704*
TOTAL:	**$46,873,079**

Cost Estimate for 10 Year, 93.5 MW PPA to Replace Capacity of CT's (Based on Oneta Offer)

Estimated PPA Cost:	$28,274,400
Debt Service for N-2 Reliability Upgrades:*	$24,506,847
TOTAL:	**$52,781,247**

Cost Estimate to Retire 93 MW of CT's and Replace with 90 MW Recip Plant

10-Year Total Fixed Costs (Fixed O&M and Capital)	$8,096,404
Labor Cost (22% reduction from CT Operation)	$30,415,420
Debt Service for New 90MW Recip Plant**	$64,467,936
Estimated Net Revenue Above the Cost of Fuel	*-$26,505,198*
TOTAL:	**$76,474,563**

* $36.46 million dollars of investment are required to maintain N-2 Reliability. This costs represents the debt service on this amount based on a 3% rate for 20 years. The total number shown represents 10 years of payments on the 20 year bond.

** $126.36 million dollars of investment are required to build a 90 MW Recip Plant. This costs represents the debt service on this amount based on a 3% rate for 30 years. The total number shown represents 10 years of payments on the 30 year bond.

In addition to the continued operation of the CTs being the lowest cost power supply option, there are added benefits that are outlined within this report.

The City should continue to evaluate its generation assets on a periodic basis to ensure that it utilizing the most cost effective resources to meet its power supply needs. The recommended timeline for future actions can be found at the end of this report.

Summary of Power Supply Resources

IPL's Resource Adequacy Requirement for 2020 is 332.8 MW and includes the peak demand forecast plus a 12% planning reserve margin. Beginning June 1, 2020 (pending the results of the SPP Network Integration Transmission Service study) IPL's Power Supply portfolio will consist of Jointly Owned Units (75.3 MW), Contracted Resources (166.7 MW), and City Owned On-System Generation (93.5 MW) totaling 335.5 MWs. Based on current load projections, this amount of capacity will meet our needs through 2022. It is anticipated that additional capacity needs beyond 2022 will be met by increased capacity purchases through the 10-Year Oneta Power Supply Agreement.

The following tables breakdown the resources mentioned above and are delineated by Off-System vs. On-System Resources:

TABLE 1 - Off-System Power Supply Resources

Resource	Resource Age (years)	Resource Fuel	Accredited Net Capacity (MW)
Jointly Owned Units:			
Dogwood Energy Facility	18	Natural Gas	75.3
Contract Resources:			
Marshall Wind Farm	3	Wind	7.1
MJMEUC – Iatan Unit No. 2	9	Coal	53
OPPD – Nebraska City Unit No. 2	10	Coal	57.6
Smoky Hills Wind Farm Phase 2	11	Wind	4
Oneta Power PPA (45-70 MW)	17	Natural Gas	45
		Total Off System Capacity:	**235.8 MW**

TABLE 2 - On-System Power Supply Resources

Unit	Resource Age (years)	Resource Fuel	Capacity (MW)
Sub J-1	50	Fuel Oil	13.3
Sub J-2	50	Fuel Oil	12.4
Sub I-3	47	Fuel Oil	16.8
Sub I-4	47	Fuel Oil	16.1
Sub H-5	47	Natural Gas/Fuel Oil	17.1
Sub H-6	45	Natural Gas/Fuel Oil	17.8
MCP Independence	1-3	Solar	*
		Total Capacity:	**93.5 MW**

*The solar resources supplied through the power purchase agreement with MC Power (11.5 MW) do not count as accredited capacity as they are not connected to the transmission system. These resources are used to alleviate the resource adequacy requirement by reducing peak demand.

The On-System combustion turbine resources currently represent 28% of the required resource adequacy requirement.

Benefits of On-System Power Supply Resources

Transmission System Reliability:

IPL currently operates its transmission system with N-2 contingency reliability, without shedding load, through transmission interconnections with other SPP members and on-system generation resources. An N-2 contingency means the transmission system can withstand two near-simultaneous failures at any point in the bulk electric system and maintain reliable electric service to customers without having to shed load.

The NERC standard for Transmission System Planning Performance Requirements (TPL-001-4) specifies the minimum standard for reliability without shedding firm load is an N-1 contingency. Utilities must plan for more extreme events (N-2) and must develop action plans to maintain reliability of the electric grid. Action plans may consist of shedding firm load, system switching, and/or dispatch of generating resources.

In the event that all on-system generation is retired and replaced with off-system resources, IPL's system would not be able to maintain N-2 reliability without additional investment in the transmission system.

The table below represents the estimated transmission system upgrade cost as determined in the 2018 Energy Master Plan Study in the event that all on-system generation is no longer available:

TABLE 3 – Total Estimated System Upgrade Costs to Maintain N-2 Reliability

Upgrade	Cost ($MM)
IPL Facilities:	
Rebuild	$26.24
Uprate	$0.42
New Transformer	$3.90
Capacitor Banks	$2.00
Affected System Facilities:	
New Transformer	$3.90
TOTAL:	**$36.46**

Opportunity Cost - Wholesale Price Volatility:

IPL's combustion turbines (CTs) may be dispatched in the event that wholesale market pricing momentarily spikes as a result of an unforeseen disturbance on the power grid. While the price for energy at IPL's Load has averaged less than $27/MWh over the last three years, price spikes do occur. As renewable energy resources are relied upon more frequently to produce electricity to serve customers the energy markets will be subject to more price volatility. The CTs are considered peaking units and only run during peak demand to maintain grid reliability and protect against high energy prices. Most vertically integrated utilities such as KCPL, KC Board of Public Utilities and City Utilities have peaking units for this reason.

- On 8/6/19 Energy prices in the SPP Energy Market spiked up to $1127/MWh, IPL was able to run all six CTs and was paid $107,783 by the SPP Energy Market for MWhs generated.
- The table below includes some additional examples of price volatility in the energy market, in which it was beneficial for the City to have available combustion turbines on the electrical system. These are not all inclusive of such events, but represent some of the events in which the turbines ran during market price spikes and produced significant revenue.

TABLE 4 – Price Volatility Example

Date	Combustion Turbines	Peak Price $/MWh	SPP Revenue	Fuel Cost	Net Revenue
4/2/2018	H5,H6	$396.04	$19,821	$3,612	$16,209
April6/20/2018	H5,H6	$211.57	$22,032	$7,603	$14,429
8/3/2018	H5,H6	$288.92	$20,975	$7,614	$13,361
4/11/2019	J1,J2,I4,H5	$321.58	$34,762	$16,042	$18,721
7/9/2019	J1,J2,I3,H5,H6	$830.68	$73,093	$49,335	$23,758
8/6/2019	J1,J2,I3,I4,H5,H6	$1,127.45	$107,783	$75,171	$32,612

Price Separation between Resources and Load:

From time to time, the transmission system can become constrained due to transmission outages and overproduction from renewable energy resources. By having a portion of its generating resources located on the City's transmission system, it protects the City from this price separation.

The table below shows a few examples when there was a large difference in energy prices between some of the different energy resources the City utilizes to meet its resource requirements for 2018 and 2019 April – September time periods.

TABLE 5 – Price Differential between Energy Resources

Real-time Energy Pricing					
Flowday	Interval	Smoky	Iatan 2	Dogwood	INDN
4/2/2018	11:00	$260.37	-$217.12	$261.34	$396.04
5/14/2018	13:00	$44.69	$17.54	$77.56	$211.57
6/14/2018	16:00	$7.22	$15.68	$68.79	$326.77
6/27/2018	22:00	-$63.48	$79.78	$22.40	$179.97
8/3/2018	17:00	-$101.39	$14.50	$107.69	$288.92
9/18/2018	16:00	$80.46	-$50.97	$170.17	$335.55
9/20/2018	14:00	$36.08	$17.91	$49.00	$192.28
5/9/2019	21:00	$924.01	$920.42	$919.21	$941.33
5/17/2019	14:00	-$3.45	$3.12	$48.86	$215.85
6/7/2019	13:00	$71.84	$47.67	$106.06	$217.79
8/6/2019	15:00	$1,130.54	$1,096.11	$1,100.11	$1,127.45

On average prices at the City's Generation/Load Node for this time period were $8.86, $3.47 and $1.48 for Smoky, Iatan 2 and Dogwood respectively per MWh higher.

Combustion Turbine Condition Assessment

As part of the 2018 Energy Master Plan, Burns and McDonnell preformed a thorough condition assessment of all six combustion turbines in the IPL fleet. The intent of this Study was to assist IPL in determining the maintenance and capital expenditures associated with operating the CTs at a level that meets or exceeds the average reliability of similar units within the United States fleet.

For this Study, Burns & McDonnell reviewed data provided by IPL, interviewed plant personnel, and conducted a walk-down of each Facility. Additionally, historical performance data was obtained through S&P Global Market Intelligence database, which compiles Federal Energy Regulatory Commission ("FERC") Form 1 data. Burns & McDonnell then used the gathered information to determine the necessary maintenance activities that would provide reliable operation of the Units over varying operational horizons.

Key findings of this assessment are as follows:

- The combustion turbines were placed into commercial service between 1968 and 1974 meaning the newest unit is 45 years old. The typical design assumes a service life of approximately 30 to 40 years, therefore the Units have exceeded the typical service life. Many power plant operators have extended the service life of units past the design life by replacing or refurbishing many components.
- While the CTGs are older, they have relatively low operating hours and have remaining useful lifespans.
- If the Units are to operate for only five more years, then very limited Project Costs are required. If the Units are to only operate for the next ten years, then minor Project Costs will be needed as compared to what would be required for 20 years of operation.
- If the Units are expected to run for an additional ten years it is recommended that the controls wiring harness and station batteries be replaced on all units. For the H machines, it is recommended to replace the starting engine clutch and refurbish the ignition valves.
- IPL should continue to proactively inspect the combustion turbines. This includes borescoping the Substation H machines every year and the Substation J and I machines every three years. It is also recommended that a combustion inspection be performed on H5 and H6 every 5 years.
- IPL should consider more regular test runs to troubleshoot reliability concerns.

Existing Combustion Turbine Economic Analysis

Based on the results of the Combustion Turbine Condition Assessment, the ten-year operating horizon was selected for economic analysis.

As part of the Energy Master Plan, Burns & McDonnell estimated the staffing levels required to continue the operation the CTs. This estimate was based on industry averages for operating simple cycle gas turbines. Below are the benchmark staffing levels that were presented in the Energy Master Plan:

IPL Benchmark Staffing:

1. Total – 23 full time positions
    a. Management/Administration/Engineering – 4
    b. Operations – 10
    c. Maintenance – 8
    d. Store Room – 1

As part of the Energy Master Plan, Burns & McDonnell estimated the Total Fixed Costs (O&M and Capital) based on the recommendations from the condition assessment. They also estimated the Labor Costs to operate six units based on the benchmark staffing level. A breakdown of these costs can be found in Appendix A.

In addition to cost considerations, the existing units generate revenue each year over and above the cost of fuel. Over the past 4 years, the average yearly revenue of the CT fleet was calculated to be $202,000. Assuming a 3% escalation factor each year, the total ten-year average net revenue for the CT fleet is $2,315,704.

The table below represents the total cost to continue operation of the six CT units for ten years:

Table 6 - Cost Estimate to Continue 93 MW of CT Operation for 10 Years

10-Year Total Fixed Costs (Fixed O&M and Capital)	$10,294,383
Labor Cost (Industry Benchmarked)	$38,894,400
Estimated Net Revenue Above the Cost of Fuel	*-$2,315,704*
TOTAL:	**$46,873,079**

Combustion Turbine Replacement with PPA

As a cost comparison to the continued operation of the CTs, the estimated costs associated with a Power Purchase Agreement for 93.5 MWs was considered based on the pricing received from Oneta Power LLC. Oneta was the City Council approved provider of replacement capacity for the planned retirement of the Blue Valley Power Plant.

In addition to the cost of the PPA, staff also considered the system upgrade costs that Burns & McDonnell provided to maintain N-2 reliability. As detailed above, the total cost for these upgrades is $36.5 million. Considering a 20-year bond at 3% interest, the yearly debt service for this would be $2.45 million. A breakdown of these costs can be found in Appendix A.

The table below represents the total costs to replace the 93.5 MWs of capacity currently supplied by the CTs and upgrading the transmission system to sustain N-2 reliability in the absence of On-System generation. Costs for existing CT demolition and employee transition costs were not included in this estimate.

Table 7 - Cost Estimate for 10 Year, 93.5 MW PPA to Replace Capacity of CTs (Based on Oneta Offer)

Estimated PPA Cost:		$28,274,400
Debt Service for N-2 Reliability Upgrades:*		$24,506,847
	TOTAL:	**$52,781,247**

* $36.46 million dollars of investment are required to maintain N-2 Reliability. This cost represents the debt service on this amount based on a 3% rate for 20 years. The total number shown represents 10 years of payments on the 20-year bond.

Combustion Turbine Replacement with On-System Reciprocating Engine Plant

For a third cost comparison, replacement of the existing CTs with a 5X18 MW Reciprocating Engine plant was evaluated. The total capacity of this plant would be 90 MWs. As part of the Energy Master Plan completed by Burns & McDonnell, 2X18 MW and 6X18 MW plants were evaluated. For the purposes of this study, a 5X18 MW plant was selected which would closely match the capacity of the current CT fleet. The total cost of this plant was interpolated from the costs that Burns & McDonnell provided in the master plan. Fixed O&M/CapEx was also interpolated from this report.

Labor was estimated using a total of 18 full time positions which represents a 22% reduction in staff that was benchmarked for continued operation of the existing CT fleet. It was assumed that the newer units would require less initial maintenance and testing.

Net Revenue was based on a capacity factor of 8.6 % that was obtained from operating statistics published by the U.S. Energy Information Administration (EIA). This capacity factor represents a five-year average between the years of 2013 – 2017 for Internal Combustion Engines in the US. The capacity factor selected assumes that the new Reciprocating Units would run approximately 3-times more that the historical operating times of the Sub H CTs.

The Net Revenue Margin used for the revenue calculation was based on the four-year average margin calculated for the Substation H CTs between the years of 2014-2018.

It is assumed that this new plant would be located within the IPL system such that N-2 reliability upgrades would not be necessary.

The table below represents the total estimated cost to replace the CT fleet with a 90 MW Reciprocation Engine Plant. Costs for existing CT demolition, permitting costs, and employee transition costs were not included in this estimate.

Table 8 - Cost Estimate to Retire 93 MW of CTs and Replace with 90 MW Reciprocating Engine Plant

10-Year Total Fixed Costs (Fixed O&M and Capital)		$7,273,824
Labor Cost (22% reduction from CT Operation)		$30,415,420
Debt Service for New 90 MW Recip Plant**		$64,467,936
Estimated Net Revenue Above the Cost of Fuel		*-$26,505,198*
	TOTAL:	**$75,651,982**

** $126.36 million dollars of investment are required to build a 90 MW Recip Plant. This cost represents the debt service on this amount based on a 3% rate for 30 years. The total number shown represents 10 years of payments on the 30 year bond.

A breakdown of these costs can be found in Appendix A.

Conclusions and Recommendations

Based on the economic evaluation results and the time it would take to implement the necessary system upgrades for N-2 compliance and additional transmission studies for the PPA, staff would recommend proceeding with the ten-year operating horizon for the existing CT fleet. As recommended in the Energy Master Plan, the value of the combustion turbines to the overall power supply portfolio should continue to be evaluated within future energy master planning efforts. The combustion turbines will eventually reach the end of their useful lives and a plan should exist well in advance of the projected retirement date.

Below is the recommended timeline for future actions:

FY 2020-2021:

- Inspect control wiring harness and station batteries on all units and replace as necessary.
- Inspect the starting engine clutch and ignition valves on the Sub H units and refurbish as necessary.
- Begin yearly borescoping of the Sub H units. Begin the 3-year cycle of borescoping the Sub I and J units.

FY 2021-2022:

- Continue borescoping efforts.
- Re-evaluate the capacity needs based on load growth.

FY 2022-2023:

- Continue borescoping efforts.
- Preform updated Energy Master Plan.

FY 2023-2024:

- Based on the results of the Updated Energy Master Plan, Continue borescoping efforts and perform a combustion turbine inspection of the Sub H units.

FY 2024-2025 through FY 2029-2030:

- Determine the retirement date for each of the CT units and follow the approved recommendations of the Updated Energy Master Plan.
- One Combustion Inspection for each of the H units if run beyond 5 years.

Appendix A

Detailed Cost Breakdown

Ten-Year CT Operating Horizon Estimated Costs:

The table below represents the Total Fixed Costs (O&M and Capital) that are based on the recommendations from the condition assessment:

10-Year Total Fixed Costs (Fixed O&M and Capital)										
Unit	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
J-1	$34,926	$538,484	$27,086	$39,004	$139,814	$30,682	$43,580	$33,340	$34,755	$36,229
J-2	$34,926	$538,484	$27,086	$39,004	$139,814	$30,682	$43,580	$33,340	$34,755	$36,229
I-3	$40,737	$544,541	$33,400	$45,586	$36,294	$37,834	$167,006	$41,113	$42,857	$44,675
I-4	$40,737	$544,541	$33,400	$45,586	$36,294	$37,834	$167,006	$41,113	$42,857	$44,675
H-5	$152,608	$640,135	$684,450	$138,326	$144,006	$149,924	$156,087	$756,850	$169,194	$163,671
H-6	$152,608	$640,135	$684,450	$138,326	$144,006	$149,924	$156,087	$756,850	$169,194	$163,671
TOTAL:	$456,542	$3,446,319	$1,489,872	$445,831	$640,230	$436,879	$733,345	$1,662,605	$493,611	$489,150

The following table represents the Labor Costs to operate six units based on the benchmark staffing levels:

10-year Labor Costs									
Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
$3,471,666	$3,558,458	$3,647,419	$3,738,605	$3,832,070	$3,927,871	$4,026,068	$4,126,720	$4,229,888	$4,335,635

The table below represents the total estimated net revenue of the CT fleet based on a 3% escalation factor per year:

10 Year Estimated Net Revenue for the CT Fleet									
Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
$202,000	$208,060	$214,302	$220,731	$227,353	$234,173	$241,199	$248,435	$255,888	$263,564

Ten-Year PPA and Reliability Upgrade Estimated Costs:

The table below represents the Oneta 10-year PPA Costs and Reliability Upgrade Debt service costs:

Oneta 10-Year Power Purchase Agreement Estimated Annual Costs				
Year	Contract Capacity Rate ($/kW-Mo)	Estimated Capacity Requirement (MW)	Contract Cost Per Year	Reliability Upgrade Debt Service
2020	$2.25	93.5	$2,524,500	$2,450,685
2021	$2.31	93.5	$2,591,820	$2,450,685
2022	$2.36	93.5	$2,647,920	$2,450,685
2023	$2.42	93.5	$2,715,240	$2,450,685
2024	$2.48	93.5	$2,782,560	$2,450,685
2025	$2.55	93.5	$2,861,100	$2,450,685
2026	$2.61	93.5	$2,928,420	$2,450,685
2027	$2.67	93.5	$2,995,740	$2,450,685
2028	$2.74	93.5	$3,074,280	$2,450,685
2029	$2.81	93.5	$3,152,820	$2,450,685
			$28,274,400	$24,506,847
		Total:	**$52,781,247**	

First Ten-Years of Cost for 90 MW Reciprocating Engine Plant:

The table below represents the Total Fixed Costs (O&M and Capital), debt service and labor based on estimates provided by Burns & McDonnell in the Energy Master Plan:

	10-Year Total Costs									
90 MW Recip Plant	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Fixed O&M/CapEx	$649,253	$665,484	$682,121	$699,174	$716,653	$734,570	$752,934	$771,757	$791,051	$810,827
Debt Service	$6,446,794	$6,446,794	$6,446,794	$6,446,794	$6,446,794	$6,446,794	$6,446,794	$6,446,794	$6,446,794	$6,446,794
Labor	$2,714,843	$2,782,714	$2,852,282	$2,923,589	$2,996,678	$3,071,595	$3,148,385	$3,227,095	$3,307,772	$3,390,467
Total:	$9,810,889	$9,894,991	$9,981,196	$10,069,556	$10,160,125	$10,252,959	$10,348,113	$10,445,646	$10,545,617	$10,648,088

The table below represents the total estimated net revenue of the CT fleet based on a 3% escalation factor per year:

	10 Year Estimated Net Revenue for the 5x18 MW Recip									
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Net Revenue Estimate:	$2,312,062	$2,381,424	$2,452,866	$2,526,452	$2,602,246	$2,680,313	$2,760,723	$2,843,544	$2,928,851	$3,016,716
Net Cost Per Year:	$7,498,827	$7,513,568	$7,528,330	$7,543,104	$7,557,879	$7,572,645	$7,587,390	$7,602,101	$7,616,766	$7,631,371