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INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

SUBDOCKET FOR REVIEW OF DUKE ENERGY INDIANA, LLC'S GENERATION UNIT COMMITMENT DECISIONS	)))	**CAUSE NO. 38707 FAC 123 S1**

ADVANCED ENERGY ECONOMY'S EXHIBIT 4

VERIFIED DIRECT TESTIMONY AND ATTACHMENTS

OF

MICHAEL JONAGAN

I. QUALIFICATIONS AND SUMMARY

Q: Please state your full name and business address.

A: My name is Michael Jonagan, 6017 Wornall Road, Kansas City, MO 64113. I am an independent consultant and expert on power plant management and operations.

Q: Please describe your work experience.

A: I have nearly 35 years of experience in global infrastructure operation, management, and financing. Most relevant to this proceeding is my background working as:

1. Operations Superintendent at the coal fired Sibley Generating Station (retired) located in Sibley, MO.
2. Vice President of Mid Continent Origination at Aquila's unregulated electricity trading subsidiary.
3. Vice President Production with operational responsibility for Aquila's regulated generating plants in Missouri, Kansas, and Colorado, including fuel procurement and regulated trading.
4. CEO of Aquila's regulated North American gas and electric utilities
5. Vice President – CIS for AES. This role had responsibility for all of AES's businesses in the Republic of Kazakhstan, which included approximately 5,600 MW of nameplate coal fired capacity and approximately 1,000 MW of hydro-electric plant capacity.

I graduated from the University of Missouri of Rolla with BS degrees in Petroleum Engineering and Mechanical engineering. I received an MS degree in Engineering Management from the University of Kansas. My CV is attached as Attachment MJ-1.

Q: Have you previously testified before the Indiana Utility Regulatory Commission ("Commission")?

A: No. However, I have previously filed testimony at the Missouri Public Service Commission and in international arbitration matters.

Q: What is the purpose of your testimony in this proceeding?

A: I have been asked by Advanced Energy Economy Inc. to evaluate various aspects of Duke Energy Indiana. LLC's ("Duke") Fuel Adjustment Clause ("FAC") filing. In particular, I have reviewed the direct testimonies of John D. Swez, Cecil T. Gurganus and Maria T. Diaz and consider the issues that they address in the context of my experience operating a number of different types of electricity generation plants.[1]

Q: Please summarize your conclusions.

A: As a result of my analysis I reach the following conclusions. First, I conclude that Duke's consumers could benefit if seasonal operation of certain coal-fired generation units was to be evaluated. As Mr. Swez notes in his Direct testimony,[2] ongoing opportunities to purchase power economically and reduce generation operational costs are likely to provide an opportunity to reduce operations during periods of low demand (shoulder months) and provide greater operational flexibility of the units during periods of high demand (summer/winter months). I recommend that the Commission direct Duke to evaluate the potential benefits of seasonal operation of some units.

Second, while I recognize that increased unit cycling implies certain higher costs, I conclude that cycling opportunities in the context of seasonal operations and pending retirement announcements could take advantage of opportunities to lower costs. The

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[1] Direct Testimonies of John D. Swez, Maria T. Diaz, and Cecil T. Gurganus, Before the Indiana Utility Regulatory Commission, Cause No. 38707 FAC 123 S1, April 29, 2020 (hereinafter "Swez Direct Testimony," "Diaz Direct Testimony" and "Gurganus Direct Testimony").

[2] Swez Direct Testimony at 15:14 - 16:14.

impact of increased cycling on maintenance would likely be more than offset by the overall reduced costs of unit operations and the avoided costs of repairs and inspections that will not be necessary if units are slated for retirement. I recommend that the Commission direct Duke to document the cost savings and avoided maintenance that can result by shifting operations to focus more on peak demand periods.

Third, it appears appropriate to carefully evaluate the costs and benefits of the steam contract that causes the Cayuga plant to maintain a minimum output level year round. One of the plant's units must be maintained at approximately 300 MW to provide steam supply that corresponds to roughly 20 MW of electric generation.[3] Cayuga plant operational data show that the units are often operated at minimum loads which implies that the plant is primarily supporting the steam contract. I recommend that the Commission consider directing Duke to conduct an evaluation of the value of the steam contract to Duke's customers relative to reduced operations of the Cayuga plant, or accelerated retirement.

Finally, given the fundamental changes in terms of the abundant supply and reduced costs of natural gas in North America and the high fixed costs of the Edwardsport plant; I recommend the Commission consider directing Duke to evaluate the economic viability of the operation of the syngas plant at the Edwardsport plant.

II. OVERVIEW

A. Background on FACs

Q: What are FACs?

A: In my experience, FACs are often (but not always) a feature of a regulated utility's ratemaking structure that provides the utility a means to recover regularly incurred variable fuel and operations and maintenance over a short time frame (typically a quarter). The costs recovered through the FAC are typically more straightforward to review than other costs

[3] Swez Direct Testimony 10:14-17 and Diaz Direct Testimony at 9:6-7.

reviewed in a typical utility rate filing. However, FACs can have a number of components depending upon their structure and the degree to which they are used to incentivize cost minimization.

Q: Please explain.

A: The incentive structure (or lack thereof) of the cost-recovery framework used for a FAC impacts how a utility will operate and dispatch its units. Providing strong incentives for the utility to optimize unit operations and reduce costs for consumers will drive efforts to find innovative means to improve generating unit operations and commercial decisions. In my experience, operational considerations vary significantly based on the design of the FAC.

Q: Please describe your experience managing the operation of power plants where most operational costs are recovered by FACs

A: During my career, I've managed the operation and dispatch of power plants in different regulatory jurisdictions. One jurisdiction with a full pass through of fuel and variable operations and maintenance ("O&M") costs via a FAC, one that provided for a 50/50 sharing of costs and off system sales margins between the utility and ratepayers, and one with no FAC. These variations in the risk/reward allocation of these costs and revenues incent different behavior by the units' owners.

Q: How does the incentive structure affect plant operations?

A: In my experience, the incentive structure significantly impacts how the generating units are operated. For example, when working with the utility that had no FAC, there was internal tension between the commercial and plant operations groups making decisions about dispatch approaches and the impact on unit operations. The commercial group was constantly pushing plant operators to explore options to lower the minimum load, increase the maximum load, increase cycling, improve heat rates, etc., to reduce the cost of power produced. On the other hand, the plant operators were more risk averse and were reluctant to take risks that might increase O&M costs. This tension pushed the plants to continuously seek cost efficient options to improve the flexibility of plant operations.

On the other extreme my experience with operations in a jurisdiction with a full pass through FAC taught me that utilities in this regulatory construct did not typically receive the incentive from the commercial dispatch group to seek out more opportunities to market available generation or to improve unit operational flexibility. Given the utility would not share in the savings from reduced fuel and purchased power costs nor from additional sales margins, the existence of a FAC created an incentive to avoid strategies that introduced risks into the plant operations and did not provide an incentive to seek opportunities to take advantage of market opportunities to increase marginal revenues.

Finally, in the jurisdiction in which I worked where the FAC required sharing of the benefits, the organization was very aggressive in marketing excess capacity and energy to other utilities and traders. Finding the best commercial transaction created value for both customers and the utility with very little operational risk for the plants.

B. Duke's FAC

Q: Please describe Duke's FAC?

A: I understand that under Duke's FAC the Commission evaluates, among other things, whether the "electric utility has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible."[4] In addition, I understand that the Commission's order on Duke's recent case[5] reviewed Duke's non-native sales profit sharing with customers that was historically structured such that Duke included in its rates a base amount of net-profits

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[4] Ind. Code 8-1-2-42(d)

[5] State of Indiana, Indiana Utility Regulatory Commission, Cause No. 45253, June 29, 2020, Order at 132-135.

that are at risk and it would have an incentive to make off-system sales to recover, but that under Rider No. 70 Duke was allowed to charge its customers for 50% of its net-profits on non-native sales that did not exceed approximately $15 million.[6] Going forward the Commission ordered the revision of the basis for Duke's recovery of unrealized non-native sales net-profits setting the $15 million to zero, required positive net-margin non-native sales within MISO to be 100% credited to customers with Duke now at risk for losses, and established an alternative "bundled" non-native sales incentive based on a single pre-existing transaction that calls for future 50/50 sharing with retail customers.[7] Thus, while Duke has a limited incentive to consider future profitable "bundled" sales, it will not share in non-system sales net-margins in MISO's markets and faces an incentive to avoid making these sales.

Q: What are the characteristics of the Duke generating units that you reviewed?

A: Attachment MJ-2 shows some of the characteristics of the Duke coal fired units whose operational costs are being reviewed in this proceeding. The Duke coal units are all fairly large,[8] and the Gibson units use super-critical boiler technology. The units' recent annual estimated capacity factors vary considerably with Cayuga Unit 2 at 29% and Duke's Edwardsport facility, a recently built integrated gasification combined cycle, at 72%. The estimated generating unit efficiencies (heat rates) vary somewhat, but all fall into a range that would be expected for these technologies. All the units except Gibson Unit 5 are wholly owned by Duke.

Q: Based on your understanding of Duke's FAC, how would expect Duke to approach decision making regarding their generating fleet?

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[6] Direct Testimony of Scott Park, Petitioner's Exhibit 1, Indiana Utility Regulatory Commission Cause No. 44348 September 14, 2018 at 3 and Petitioner's Exhibit 1-A (SP) (which identified $7.4 million in customer charges associated with off-system sales).

[7] Ibid.

[8] The only exception is the Gallagher units which rarely operate and I understand are to be shut down in 2022.

A: I would expect Duke to try to minimize fuel costs and maximize off systems sales margins for the benefit of their rate payers, but with a low/no risk strategy. In other words, I would not expect Duke to undertake a perceived risky approach to operating its units with the objective to reduce fuel and purchase power costs. All of the benefits flow to ratepayers and the risks and costs flow through to Duke's shareholders. Additionally, the testimony of Mr. Swez confirms there are hours when Duke's coal fired plants are operated with marginal economics and at negative margins when their calculation of the costs of cycling are greater than the totality of operating at negative margins.[9] Based on this, I would conclude that there is an opportunity to reduce the operations at negative margins and thereby reduce costs to customers, but there is little or no incentive for Duke to explore these opportunities.

Q: Are there factors that might cause to Duke to prefer dispatching its own generating units?

A: Yes. For example, if Duke can dispatch a unit at a cost that is at or even slightly above the expected average daily price (or expected multi-day prices as appropriate) I would expect them to dispatch. Once the unit is on line, even a small negative margin could be a reasonable option premium assuming the potential for sales of energy and ancillary services. Additionally, it would be likely that Duke would have a bias towards dispatching its own units (all other things being equal). Dispatching its own units versus purchases in the market increases the capacity factor of their coal plants and reinforces the argument that the plants are needed for reliability and are low cost resources for Duke's ratepayers.[10]

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[9] Swez Direct Testimony at 9:12-19 and 8:9-16.

[10] I am not commenting here on the particulars of Duke's rate treatment for these units, but simply making the observation that low unit capacity factors indicate reduced reliance on the generating units.

III. DUKE'S COAL GENERATION PLANTS

Q: In your experience, what are some of the options that a utility such as Duke could consider to improve unit operational flexibility?

A: Operators of large coal fired plants have several options to increase operational flexibility and thereby reduce the number of MWH's generated at negative margins. In the following sections I review some of the fairly common methods that I've seen studied and/or implemented and how these might be feasible for Duke.

1. Seasonal Operation

Q: Please explain how seasonal operations could be a beneficial operational approach to be evaluated by Duke?

A: A reasonable option to consider for plants with marginal economics would be a transition of some units to seasonal operation. In the case of Duke's plants it might be feasible to take some generating units out of service during lower load months, typically spring and fall.[11] Unless there are some very specific and/or unusual circumstance related to the design or operation of a specific plant, this type of transition should not require extensive capital improvements or major changes in operations. This type of strategy could have several benefits. First, the plants are not subject to the wear and tear associated with normal operations during this period of time. To the extent normal scheduled outages have compressed time frames that result in overtime and the use of contractors to complete the maintenance on time, this work could be done at a more casual pace and potentially lower

[11] I recognize that Duke may need to consider the time periods available and confer with MISO. However, there does seem to be precedent in MISO to move coal fired plants into seasonal operations. The SWEPCO and CLECO Dolet Hills Power Station and Xcel's Allen S King and Sherco Unit #2 have or will transition into seasonal operations (See, for example, Minnesota approves Xcel Energy plan for seasonal dispatch of 2 coal units, July 16, 2020, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/minnesota-approves-xcel-energy-plan-for-seasonal-dispatch-of-2-coal-units-59465244 and SWEPCO, Cleco eye 2021 retirement of Dolet Hills coal plant in Louisiana, May 13, 2020, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/swepco-cleco-eye-2021-retirement-of-dolet-hills-coal-plant-in-louisiana-58612640).

costs. Finally, the unit might consume less auxiliary power during a prolonged outage where there is no need to maintain immediate operational readiness.

Another interesting possibility is the potential impact on implementing a more aggressive cycling strategy during the on peak season. Given the current timeline for plant retirements and a potentially compressed operating season as described previously, it does appear that Duke could be in a position to take a much more aggressive view on the economics of cycling. The following are some specific comments on Duke's plants. Seasonal operation at Cayuga will be problematic as long as the steam supply contract remains intact. Additionally, Edwardsport could have complications due to syngas operations. However, Gibson does not appear to have these types of constraints and it would seem to be a good candidate to have some of the units studied for seasonal operations.

2. Increased Unit Cycling

Q: How might increased unit cycling be considered by Duke?

A: In my experience there is industry consensus that cycling large coal fired generating units leads to increased forced outage rates and higher O&M costs over the long term. Unfortunately there is not consensus regarding a sound methodology for predicting these future costs. Even if there was a good methodology, each generating plant has its own set of unique issues that make it difficult to put a single "price" on the cost of cycling units in a plant. At the end of the day, each plant owner makes decisions about when the losses of selling electricity at a negative margin out-weigh the costs of cycling a unit. I do not have sufficient data or experience with Duke's units to state an opinion on Duke's methodology for calculation these costs. However, I offer the following observations: the existence of the FAC would direct 100 percent of lower fuel/power costs resulting from increased cycling to Duke's ratepayers. Additionally, Duke would bear most of the increased O&M costs resulting from increased cycling. Based on my experience, if the risk/reward of increased cycling were shared between Duke and its ratepayers, it is possible that Duke might be more willing to invest resources towards reducing the costs and risks of cycling.

Q: Please provide some examples that can be considered for Duke's plants.

A: Below are some specific considerations based on Duke's plants:

Gibson Generating Station – Given that Unit 5 has a different ownership structure than Units 1-4 it is entirely possible that an operating strategy that meets the needs for Unit 5 owners might be different than units wholly owned by Duke. On June 20, 2019 Duke announced a plan to accelerate the retirement of all the units at Gibson. For example Gibson Unit 4's retirement was moved from 2041 to 2026. It seems reasonable to assume there might be a lot of startups "left in the tank" for Gibson #4 before now and 2026. Further, it could be reasonable to assume that many of the future costs associated with cycling might never be realized before retirement. For example, Mr. Gurganus stated in his testimony that increased cycling could force Duke to shorten the intervals for generator field inspections to approximately 5 years versus 10 years.[12] This doesn't seem very likely given that Gibson Unit 4 has only 6-7 years of remaining life. Further, Mr. Gurganus states that, "In addition, frequent cycling results in higher net and operating heat rates on the units, as the units consume more start up fuel and more off line auxiliary power. Units that are frequently cycled generally operate at lower average loads, which are less efficient than operating at higher average loads. Similar to the point above, this also results in higher CO_2 emission intensity (lbs/MWHR)…" [13] I strongly disagree with this logic. Mr. Gurganus is leaving out half of the equation. During the time the Duke unit would be off line, that "missing" generation is being supplied from other sources. In this case the increased CO2 emission intensity would be more than offset by the alternative generating source. Thus, it is

[12] Guganus Direct Testimony at 12:10-13.

[13] Id. at 12:18-22.

reasonable for Duke to reconsider its approach to estimating the future costs of cycling at Gibson given remaining life of the plant.

Cayuga – Given the constraints of the steam supply contract it does not seem likely that increased cycling has a lot of potential to result in savings for Duke's rate payers. However, in the absence of a steam supply contract and given Duke's stated plan to retire Cayuga Units 1 and 2 by 2028, it seems that a much more aggressive approach to cycling might be feasible given the short remaining life of the station.

Edwardsport IGCC – To the extent Edwardsport remains primarily a coal fired plant and given the complexities of the syngas facilities increased cycling does not appear to be a viable option unless there are very low wholesale market price conditions that are expected to last for significant time. If the plant transitioned to a traditional gas fired only combined cycle plant, there would be improved opportunities for cycling as these plants are generally more flexible as it relates to cycling. As a confirmation of this, in Mr. Swez's testimony he states that during times when the syngas trains are unavailable, Edwardsport is typically offered to MISO on natural gas with a commitment status of Economic and can be committed and dispatched at MISO's discretion.[14] Additionally Duke is not predicting a "fundamental return to higher gas prices"[15] which implies the economics of coal operation have been diminished at Edwardsport.

3. Reducing the minimum operating load.

Q: How might reducing the minimum operating load be considered by Duke?

A: Gibson Generating Station – These plants have super critical boilers and require a minimum feedwater flow as part of their original design which affects the minim operating load. I have many years of experience with the operations of super critical units.

[14] Swez Direct Testimony, 26: 5-8

[15] Swez Direct Testimony, 27: 17-21

Complicating matters further at Gibson is the fact that SCRs (Selective Catalytic Reduction modules for reducing nitrogen oxides) have been retrofitted onto the boiler for NOx reduction. SCR's have required minimum combustion gas temperature for design operation that also affects minimum load levels. Combustion gas temperature at lower operating loads is directly correlated the plant generating load. However, I understand that Duke expended considerable effort following its SCR retrofits to achieve minimum load levels consistent with the Gibson units' original design.[16]

Cayuga Station – The analysis for Cayuga is complicated by the steam supply contract currently in place. When steam is being supplied to Duke's industrial customer, the minimum load from the unit supplying the steam is 300 MW.[17] As Attachment MJ-3 shows, the requirement that a Cayuga units be on-line at a minimum output level has recently resulted in a growing number of hours of units operations at or near minimum load (300-350 MW in the attachment). Given this operational constraint, the overarching question is the economic viability of the steam supply contract as there may be value in assessing options to reduce Cayuga's operations at minimum load. If the steam supply contract is "forcing" the operation of a power plant irrespective of electricity market economics, then the steam supply contract would have to generate significant economic benefits for ratepayers. The testimony of Ms. Diaz states that current steam supply contract can be terminated by either party.[18] In my opinion, Duke should evaluate the costs and benefits of providing notice to terminate the steam supply agreement. This evaluation would take into account (among other things), the ability to consistently utilize a lower minimum load, the ability to leave both units off line during periods of low market prices,

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[16] See, for example, At Duke Energy's Gibson Generating Station in Owensville, Indiana, SBS Injection® technology has been used for SO3 control on all five units since 2005, https://www.power-eng.com/2017/03/09/scr-performance/, where Duke's efforts to optimize minimum load operations are reviewed.

[17] Ibid.

[18] Diaz Direct Testimony at 8:11-13.

the possibility of seasonal operation and finally the possibility of accelerating the plant's retirement.

Edwardsport IGCC - Duke states that the Edwardsport Plant's low incremental cost means that the plant typically operates at full load.[19] If this is case, it might not make a lot of sense at this time to evaluate ways to reduce the minimum load options for the plant.

IV. CONCLUSION

Q: Can you please summarize your testimony?

A: Yes. First, I conclude that Duke's consumers could benefit if seasonal operation of certain coal-fired generation units was to be evaluated as it could reduce costs incurred under Duke's FAC. Next, I conclude that cycling opportunities in the context of seasonal operations and pending retirement announcements could take advantage of opportunities to lower operational costs at Duke's units. Third, it appears appropriate to carefully evaluate the costs and benefits of the steam contract that causes the Cayuga plant to maintain a minimum output level year round as this could also reduce costs to consumers under Duke's FAC. Finally, evaluating the operation of the Edwardsport plant as a traditional gas fired only combined cycle plant could improve opportunities for cycling as gas-fried combined cycle plant operation allows for greater operational flexibility.

Q: Does this conclude your testimony at this time?

A: Yes.

[19] Swez Direct Testimony at 26: 3-5.

VERIFICATION

I hereby verify under the penalties of perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

Dated: July 30, 2020

Michael Jonagan

Michael Jonagan

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Kansas City, MO 64113
mjonagan@yahoo.com

Mr. Jonagan is an expert in the operation and management of electricity generation stations using various technologies. He is intimately familiar with electricity production processes, their underlying cost structures, and how to achieve and maintain high efficiency generation unit operations.

Employment History:

July 2016 – present
Consultant
Kansas City, MO, USA

July 2020
Affiliated Consultant, Analysis Group

March 2013 – June 2016
Senior Director – Business Development
Corridor InfraTrust Management, LLC
Kansas City, MO, USA

April 2004 – December 2012
Vice President – CIS
AES Corporation
Almaty, Kazakhstan; Kiev, Ukraine; London, United Kingdom

January 1986 – July 2003
Aquila, Inc as follows:

February 2003 – July 2003
Senior VP Merchant Services
Kansas City, MO, USA

September 2002 – January 2003
CEO – North American Utilities
Kansas City, MO, USA

October 2000 – August 2002
COO – United Energy
Melbourne, VIC, AUS

February 2001 - March 2002
CEO – UeComm
Melbourne, VIC, AUS

February 2000 – September 2000
VP – Regulated Generating Plants
Kansas City, MO, USA

March 1996 – January 2000
VP – Mid-Continent Electricity Trading and Origination
Kansas City, MO, USA

April 1991 – February 1996
Plant Superintendent – Gas Turbine Plants
Greenwood, MO, USA

January 1986 – March 1991
Operations Superintendent – Sibley Generating Station
Sibley, MO, USA

Education
BS Petroleum Engineering, University of Missouri – Rolla, 1983
BS Mechanical Engineering, University of Missouri – Rolla, 1985
MS Engineering Management, University of Kansas, 1996

Electricity Industry Experience

At AES Mr. Jonagan directed all of AES's businesses in Kazakhstan and Ukraine. AES had five generating stations in Kazakhstan owning and operating three coal fired power plants and operating two run of the river hydro plants under a 20 year concession. In addition to the power plants, AES owned a large surface coal mine, operated two electricity distribution networks and one heat distribution network under a contract with the Republic of Kazakhstan. In Ukraine AES operated an electric distribution business and was not involved in power generation.

In Kazakhstan Mr. Jonagan managed the rehabilitation of several large coal-fired units. When AES purchased the coal-fired plants their name-plate capacity was approximately 5,500 MW. However, when Mr. Jonagan started in Kazakhstan the coal-fired plants were only capable of generating 3,500 MW. In Kazakhstan Mr. Jonagan was charged with increasing the capacity and reliability of the plants. He focused his efforts on the Ekibastuz GRES 1 power plant located in Ekibastuz Kazakhstan, an 8 unit 4,000 MW coal-fired power plant (one of the largest coal plants in the world). At the time he arrived the plant had only 5 units that were operable, with an operating capacity of about 1,700 MW. After three years the capacity of the 5 operating units at Ekibastuz were restored to their original 500 MW name plate rating each; an increase of about 800 MW. Mr. Jonagan then started the process of bringing one of the old mothballed units back into service contracting the Hungarian engineering firm ERBE to perform all studies and cost estimates for this phase of the project. However, at about this time the Republic of Kazakhstan expressed interest in purchasing the plant and AES ultimately sold Ekibastuz to a state controlled copper mining company.

Mr. Jonagan then focused on the two other coal fired plants. Mr. Jonagan managed upgrades at these facilities and oversaw the contracting process to bring on board an engineering, procurement and construction contractor. At one plant the once through cooling system was replaced with cooling towers and at the other plant an old 25 MW turbine generator set was replaced with a new 50 MW turbine generator set sourced from China. Both of these projects were under construction at the time Mr. Jonagan left Kazakhstan in 2012.

The name plate capacity of the two hydro plants AES operated under a concession was a little over 1,000 MW. Mr. Jonagan also managed the operations and maintenance of the hydroelectric generation stations while in Kazakhstan.

Prior to joining AES, Mr. Jonagan worked in Australia at Aquila's gas and electricity distribution businesses in Melbourne and upon his return to the US was named CEO of North American Utilities. Aquila had gas and electric utility businesses in seven US states and two Canadian provinces. All of the businesses were earning well below their allowed regulated equity rates of return and needed a significant restructuring to provide better cost transparency for the various jurisdictions of operation. Mr. Jonagan completed the restructuring of Aquila's regulated utility businesses.

While at Aquila Mr. Jonagan also served as a Vice President of Regulated Generating Plants. In this role he was responsible for all of Aquila's regulated generating stations in Missouri, Kansas, and Colorado. The total capacity of these plants was approximately 1,600 MW and his primary focus was implementing a natural gas hedging program for the plants.

Mr. Jonagan also served as the Superintendent for all four of Aquila's gas turbine plants for five years. These plants were composed of eight generating units at the four locations with a total generating capacity of 345 MW. He was responsible for all aspects of plant maintenance and operations, completed a comprehensive capacity increase program at the plant, and modified the four unit Greenwood Energy Center for dual fuel capability allowing the plant to burn natural gas. He also managed the construction of the natural gas pipeline extension to the plant. He managed all aspects of these projects including cost projections, economic justification, bidding process, engineering, regulatory, construction, and commissioning.

Mr. Jonagan's professional career began as an engineer at the Sibley Generating Station in Sibley, Missouri (U.S.). The plant was a three unit 500 MW coal fired power plant (retired at the end of 2018). Mr. Jonagan worked at the station for approximately 5 years and ultimately became responsible for plant operations. In this position he managed the plant heat rate program (the measure of the plant's efficiency when converting fuel into electricity), was responsible for training control room operators, drafted standard operating procedures, and created the annual and five-year budgets for the operations department.

Unit Attributes and Operational Information (2019)
Cayuga, Gibson Station, Gallagher, Edwardsport

Plant Name	Unit	Ownership	Unit Start Year	Summer Capacity (MW)	2019 Operating Capacity Factor (%)	Average 2019 Net Heat Rate (Btu/kWh)	Number of Starts in 2019	Minimum Operating Hourly Load (MW)	Source of the Coal (State)	Boiler Type
Cayuga	1	Wholly Owned	1970	500	51	9,790	7	265	IN	Subcritical
	2	Wholly Owned	1972	495	29	9,971	11	265	IN	Subcritical
Gibson Station	1	Wholly Owned	1976	630	51	9,320	11	200	IN/IL	Supercritical
	2	Wholly Owned	1975	630	51	10,327	8	200	IN/IL	Supercritical
	3	Wholly Owned	1978	630	39	10,219	14	200	IN/IL	Supercritical
	4	Wholly Owned	1979	622	39	9,774	11	200	IN/IL	Supercritical
	5	Joint Ownership	1982	620	41	9,677	12	620	IN/IL	Supercritical
Gallagher	2	Wholly Owned	1958	140	1	9,984	6	45	KY/WV	Subcritical
	4	Wholly Owned	1961	140	1	10,116	4	45	KY/WV	Subcritical
Edwardsport	IGCC	Wholly Owned	2013	595	72	8,909	3	393	IN	IGCC

Notes:

[1] A unit start is considered to be a period where a unit increases from 0 MWh of generation to at least 100 MWh of generation without any periods of 0 MWh of generation in between.

[2] Gibson Station Unit 5 is jointly owned with Indiana Municipal Power Agency and Wabash Valley Power Association Inc.

[3] Coal source state is determined using 2017 and 2018 fuel receipts.

[4] The Edwardsport operating capacity factor represents the average capacity factor for the ST and CT units.

[5] For Gibson Unit 5 the EIA reports a minimum output level that is considerably higher than the level the unit can achieve.

Sources:

[A] Hitachi ABB Power Grids.

[B] EIA Form 923, (2017, 2018).

[C] EIA Form 860, (2018).

[D] S&P Global Market Intelligence.

Cayuga Total Generating Hours by MWh
2015, 2018, 2019

	2015		2018		2019	
Hourly Generation	**Cayuga Unit 1 Total Hours of Generation**	**Cayuga Unit 2 Total Hours of Generation**	**Cayuga Unit 1 Total Hours of Generation**	**Cayuga Unit 2 Total Hours of Generation**	**Cayuga Unit 1 Total Hours of Generation**	**Cayuga Unit 2 Total Hours of Generation**
0 MWh - 50 MWh	15	16	18	10	15	18
50 MWh - 100 MWh	6	12	5	8	4	13
100 MWh - 150 MWh	7	27	3	5	6	13
150 MWh - 200 MWh	8	17	9	4	4	8
200 MWh - 250 MWh	469	87	1,308	643	830	95
250 MWh - 300 MWh	393	230	495	328	480	92
300 MWh - 350 MWh	2,080	1,311	1,468	2,535	4,320	2,453
350 MWh - 400 MWh	875	416	604	764	674	452
400 MWh - 450 MWh	984	474	683	741	496	272
450 MWh - 500 MWh	2,661	916	2,175	1,357	575	284
500 MWh - 550 MWh	718	1,175	876	1,749	90	242
Total	**8,216**	**4,681**	**7,644**	**8,144**	**7,494**	**3,942**

Note:
[1] Hours with zero generation are excluded.

Source:
[A] Hitachi ABB Power Grids.