RESPONSE TO COMMENTS ON 2018 CWLP IRP

Following the release of the IRP, CWLP requested public comments. CWLP received many comments, including some that questioned the results, misinterpreted the results or questioned information that was not included in the report. CWLP shared with The Energy Authority, Inc. (TEA) the comments that were relevant to TEA's IRP work, and requested TEA provide clarification.

TEA has compiled these responses to the questions posed during the comment period following the publication of the 2018 City Water, Light and Power (CWLP) Integrated Resource Plan (IRP). TEA will address comments about the recommendations, study assumptions, and the inclusion of certain technologies and options. Other considerations, including social impacts, are outside of TEA's purview.

RECOMMENDATIONS

Based on the comments shared with TEA, some confusion exists about the recommendations. Because all public utilities should consider risk and reliability along with cost, there are some fundamental differences between the least-cost reference case solution of the IRP and TEA's recommendations.

Firstly, TEA recommends retaining Dallman 4 until at least the next IRP cycle at this point in time. The stakeholder comments addressed several reasons for this retention, including maintaining grid resiliency and avoiding transmission upgrade costs. As stated on page 69 of the report, Dallman 4 provides "fuel diversity and dispatch optionality [in] a predominantly gas-driven market". Although some scenarios retired Dallman 4 economically and replaced it with a 200 megawatt (MW) combustion turbine (CT), TEA does not recommend this course of action because the marginal improvement was only 3% over 20 years compared to the reference case. Furthermore, the possibility exists that new regulations could make fossil-fueled generation not viable before the debt of the new CT has amortized. The CT was included in the model because transmission studies by CWLP show a unit of that size is required for system reliability. For a more complete list of the reasons behind the Dallman 4 recommendations, see page 69 of the report. Due to the rapid advancement of technology and recent price trends, this decision should be reevaluated in a few years. In the interim, CWLP could feasibly "start thinking about a transition plan", as stated by one commenter. Though TEA provides recommendations as part of the IRP process, creating a specific action plan is beyond TEA's scope and must be performed by CWLP.

To ensure CWLP acquires the most competitive pricing of new assets, TEA recommends putting out a Request for Proposal (RFP). The recommendation is primarily for renewable assets, but may also include non-renewable assets. No specific fuel is excluded from this RFP recommendation. TEA does not recommend that CWLP accept one of its current offers without additional discovery and analysis. Renewable energy prices have dropped dramatically since the signing of the Crystal Lake wind contract, and an RFP process can help CWLP take advantage of these energy price reductions.

TEA recommends retiring Dallman Units 1-3 as soon as feasible, due to noncompetitive operating costs. Though the model retires the units in 2020, there may be real-world considerations, which would necessitate a longer period of time before retirement. Among these are existing capacity obligations, market requirements and regulations, permitting and construction timelines, social impacts, and other planning reasons. TEA supports CWLP's best efforts to affect a conscientious and cost-efficient transition. Any change in the recommended decision to retire Dallman units 1-3 would require significant price reductions to the coal price in the Flat Coal Price scenario.

As discussed in the Overview of Available Resource and Technologies, energy efficiency and DSM can have a significant impact on a utility's system and load. One key technology to affect this change is advanced metering infrastructure (AMI), which allows two-way communication between the utility and the customer. Many EE and DSM programs require this technology to function. Since Springfield is not currently equipped with AMI, TEA did not include those programs in this study. The information used to determine which programs to model includes existing literature on EE/DSM programs, data from CWLP's current and previous programs, and factors such as expected participation by customer class, energy reduction, and administrative and development costs to determine economic viability. The programs that passed this initial test were included in the final model with the supply-side generation to determine their effect on the NPVRR. TEA's recommendations to CWLP include conducting further analysis in this area, including the potential implementation of AMI meters, which could significantly expand the amount of EE/DSM programs CWLP offers (pg. 70). As mentioned in the comments, CWLP could also explore the option of examining the subsidies of programs currently deemed uneconomic, and adjusting them so that the project costs do not exceed their economic benefits. For additional description and cost information of the DSM programs included, see Potential Energy Efficiency and Demand-Response Programs on page 51 and Energy Efficiency and Demand-Response Programs on page 26.

INCLUDED COSTS

This IRP is the result of an impartial consideration of new and existing resource options available to CWLP to meet Springfield's future electric demand. Analysis includes consideration of capital and operating costs associated with existing and new resource options. Social impacts were outside the scope of this study as the objective of this IRP was to minimize CWLP's future revenue requirements.

Furthermore, this IRP did not consider any unavoidable costs common to all plans. The purpose of the IRP was to find a path forward that would "minimize the incremental Net Present Value of the Revenue Requirements . . . while honoring system and regulatory constraints" (pg. 16). Because decommissioning costs are sunk and must be paid eventually, they have negligible impact on the incremental NPVRR and were not included in the study. However, costs of transmission upgrades associated with unit retirements were included, because they may be avoidable as the transmission grid changes. For more information on the NPVRR calculation, please see the Methodology starting on page 16 of the report.

Similarly, the $48 million environmental compliance cost cited on page 69 includes only costs of upgrades and installations CWLP will avoid if Dallman units 1-3 are retired. TEA has assumed that Dallman 3 will need to be retrofitted with a dry ash handling system at a cost of approximately $26 million in order to comply with the Effluent Limitations Guidelines (ELG) and Coal Combustion Residuals (CCR) regulations if it is not retired in the near future. The remaining $22 million of the $48 million environmental compliance cost are for similar retrofits to Dallman 1 and 2. TEA has not evaluated options to reduce power production costs from Dallman 3 or 4. These costs were identified in an "Effluent Limitation Guidelines and Coal Combustion Residual Final Rules Study", performed by Burns & McDonnel in 2016.

The capital cost of all new builds were included in the model. The capital cost of building the facilities associated with the renewable Power Purchase Agreements (PPA) were not included or discussed because PPAs are usually structured such that the resource owner, not the holder of the contract, is responsible for the capital costs of construction. If capital costs must be passed on, they will generally be included in the PPA price.

In some scenarios, Dallman 4 is replaced by a CT based on a General Electric (GE) Frame 7F. TEA developed the capital cost estimate of approximately $120 million (2018 $) based on information provided in the Gas Turbine World 2018 GTW Handbook. This publication provides a budget price of $47 million (2018 $) for a unit of this size and states, based on its knowledge of past projects, that "a useful rule of thumb is to double the equipment price for estimating total installed cost" (Gas Turbine World 2018) including construction, land, engineering, testing, permitting, natural gas pipeline construction, and project contingency. TEA applied a multiplier of 2.4 based on analysis of actual project costs.

A final minor adjustment to account for regional differences in project costs increased the cost by approximately 3.5%. This regional adjustment was provided by the US Energy Information Administration's (EIA) "Cost and Performance Characteristics of New Generating Technologies" in the Annual Energy Outlook 2018 – Table 8.3 and includes factors such as labor and land cost.

TEA based operations and maintenance costs for this combustion turbine on the US EIA's "Cost and Performance Characteristics of New Generating Technologies" from its 2018 Annual Energy Outlook – Table 8.2. For the General Electric model 7F.04, a conventional combustion turbine, fixed O&M was assumed to be 17.67 (2017$/kW/yr), and variable O&M is assumed to be 3.54 (2017$/MWH).

The renewable PPA prices modeled are based on actual offers by vendors. Although lower cost PPAs may be available in nearby markets or by another vendor, these options may not be viable to CWLP due to additional costs associated with transporting energy or with signing a contract that does not include capacity. The purpose of the recommended Request for Proposal (RFP) is for CWLP to find the most economic option. Wind contract prices following the expiration of production tax credits (PTC) were based on a current offer, the price escalation included in that offer, the government PTC on that offer based on its construction dates, and a 1.5% learning rate through 2025.

EXISTING UNITS

GAS-FIRED COMBUSTION TURBINES

The 110 MW Interstate gas turbine, CWLP's only unit capable of operating on natural gas, has an average full load heat rate of 11.6 MMBtu/MWh and an incremental heat rate of approximately 9.7 MMBtu/MWh. With an assumed minimum delivered natural gas cost of $3.20/MMBtu and a variable O&M of $6.00/MWh, the approximate incremental cost is $37/MWh. This is significantly above average market prices. Therefore, it would only be used during periods with large price spikes, which is a normal usage for similar type units.

Assumptions for the new CT selected as an alternative for Dallman 4 are based on a 198 MW General Electric Frame 7F.04 with a full-load heat rate of approximately 9.8 MMBtu/MWh on natural gas. Even this more efficient CT would be expected to operate primarily in very high load periods or when required to meet local reliability and voltage support requirements.

While more efficient CTs are considered in the analysis, the GE 7F.04 has a lower estimated capital cost than the more efficient alternatives. Therefore, when the model selected any CT, it selected this model on a least-cost basis instead of other modeled CTs.

DALLMAN STATION UNIT 3

Technically, Dallman 3 could likely be mothballed for an indefinite period. This alternative was not considered in the analysis. There are nontrivial ongoing costs associated with mothballing coal-fired power plants. Some operational costs include boiler preservation, building heating, motor maintenance, catalyst storage and permitting. Restarting efforts can carry significant costs as well, requiring hiring/training and some recommissioning of the dormant systems. In essence, to maintain the unit in a condition that would facilitate a future restart would likely increase costs above the retirement scenario. Additionally, the risk of increased environmental regulations could adversely impact feasibility of mothballing and restarting this unit.

Rebuilding the boiler of a generator requires that unit to adhere to new source performance standards and environmental regulations once it comes back online. Therefore, if the boilers of Dallman 3 or 4 were rebuilt in an attempt to reduce operating costs, CWLP would also have to update the units so that they conform to emissions control technology standards for new units.

NEW AND EMERGING TECHNOLOGIES

ENERGY STORAGE

Energy storage assets could theoretically contribute to the future revenue streams via ancillary services and resource adequacy. All of the batteries modeled were awarded capacity revenues consistent with current Midcontinent Independent System Operator (MISO) standards. However, long-term planning models such as those used for most IRPs are not well suited to capturing frequency regulation revenues due to the market-wide co-optimization algorithms MISO uses to calculate those revenues. In addition, the economic value of frequency regulation will likely decline as more storage devices enter the market while demand remains relatively fixed. Thus, those revenues were not included in this IRP. At the time of this IRP, frequency regulation is the only ancillary market in which energy storage resources can participate in. It may be appropriate to include these revenue streams in future IRPs after the conclusion of efforts at Federal Energy Regulatory Commission (FERC), MISO, and other Regional Transmission Organizations (RTOs) to allow energy storage devices to participate in additional ancillary markets. In summary, battery storage participation in RTO markets, and how it can be modeled in an IRP, is evolving quickly. It may make sense to fully model additional revenue streams in future IRPs.

RENEWABLE PENETRATIONS

To capture expected renewable penetrations and the grid resiliency associated with those penetrations, TEA used the 2018 MISO Transmission Expansion Plan. The IRP uses MISO's renewable penetration assumptions. In 2032, MISO estimates renewable penetration to be approximately 19% of energy in the Continued Fleet Change (CFC) scenario and 35% in the Accelerated Fleet Change (AFC) scenario. According to MISO, the equivalent value in 2017 was 12%. Refer to MISO's MTEP18 for more information on the reasoning behind these assumptions. The MTEP is extensively vetted by industry stakeholders and has historically been the diligence component behind billions of dollars of high-value transmission projects designed to maintain reliability and improve system economics. It is a nodal model created by a team of experts at MISO to determine the necessity and economics of future builds, and its various futures served as market models in all of the IRP scenarios.

JET EADS

TEA has not evaluated the Jiangnan Environmental Technology Inc. (JET) efficient ammonia desulfurization (EADS) technology as an alternative to reduce power production costs from Dallman 3 or 4. The JET EADS technology is unlikely to mitigate the need to convert Dallman 3's ash handling system to a dry system and avoid the associated $26 million expense.

TEA reviewed material provided by the Illinois Coal Association with respect to the JET EADS technology. In order to evaluate this technology, detailed cost and performance information will be required.

In its September 12, 2018 presentation to the Illinois Flue Gas Desulfurization Task Force, JET has provided some insight into the cost and performance of the EADS technology. On page 30 of that presentation, an example of operating cost for the EADS vs. limestone scrubber for a 1,300 MW generating station is provided.

In this example, the EADS operating cost is over twice the operating cost of the limestone system. This higher operating cost is more than off-set by JETs estimate of revenue received from the sale of ammonium sulfate. However, this comparison does not include any capital cost recovery for construction of the EADS technology.

The example does show that the economics of EADS are highly dependent on the price spread between selling ammonium sulfate and purchasing ammonia. Therefore, detailed analysis of the markets for these two commodities would be a necessary part of evaluating this alternative. It is also noteworthy that this technology, unlike CWLPs current limestone scrubbers, requires on-site storage of substantial quantities of anhydrous ammonia, which is a dangerous chemical and would be subject to significant regulatory and public scrutiny.

FUEL PRICE ASSUMPTIONS

COAL PRICE

A key assumption in the development of this IRP is the future cost of coal for CWLP generation. TEA developed a reference case projection and high and low price projections for use in alternative scenarios. For coal prices used in the study, see Figure 12 on page 31 of the report.

The 2019 value in each of the three pricing scenarios is $1.84/MMBtu, consistent with CWLP's current delivered pricing.

The reference case projection increases to a nominal $2.71/MMBtu in 2039. In developing the reference case coal price projection, TEA assumed an average escalation rate between 2019 and 2039 consistent with the assumed inflation rate of approximately 2% per year. Therefore, the price of coal remains constant in real terms in the reference case. TEA also assumed CWLP would continue pricing its coal with 5-year, fixed-price contracts.

The high coal price projection for 2039 is $3.14/MMBtu in nominal dollars. The escalation rate between 2019 and 2039 averages approximately 2.7% per year. This rate is only slightly above the rate in the 2018 MTEP CFC scenario, which was used as the basis for this IRP's reference case.

The low coal price projection held the existing price constant in nominal dollars for the entire study period resulting in an overall real price decline during the 20-year period of approximately 33%. Study results indicate that Dallman Units 1-3 are not economically viable even in the low price scenario.

The following information support the conclusion that the coal price projections used in the IRP are reasonable:

- The coal price projection used in the highly-vetted 2018 MISO Transmission Expansion Plan (MTEP) starts at $2.09/MMBtu in 2019 (13.6% higher than CWLP reference case) and increases to $3.43/MMBtu (26.6% higher than CWLP reference case). The growth rate averages 2.5% annually, a half of a percent higher than that of the reference case projection used in this IRP.
- The Interior US minemouth coal price in the US EIA's 2018 Annual Energy Outlook increases in real terms (2017 dollars) at an average annual rate of 0.1%. This rate is comparable to the 0% change in the real price assumed in CWLP's reference case.
- Form EIA-923 data (accessed through ABB's Velocity Suite) indicates that CWLP's free on board (FOB) coal cost at the Viper mine of $1.48 was $0.178 below Foresight's weighted average FOB price at its Illinois Basin mines (Mach #1, MC #1, and Shay #1) and $0.169 below the weighted average FOB mine price for Illinois Basin coal in 2018. Thus far in 2019, CWLP's FOB cost continues to be priced below that of Foresight and the Illinois Basin overall.

While TEA did not expressly recommend that CWLP issue an RFP for future coal supplies in this IRP study, CWLP staff may again use this strategy, subject to the terms of CWLP's existing supply agreement.

NATURAL GAS PRICE

The natural gas pricing is another key assumption used in this IRP. Natural gas prices have become increasingly competitive over the past decade due to growing shale gas production in the US. Since 2015, 97.6% of the daily natural gas prices at the Henry Hub have been less than $4/MMBtu, and 99.7% have been under $5/MMBtu. During the last ten years, daily natural gas prices at the Henry Hub have reached $8/MMBtu on only two days.

As described in the IRP document, the reference natural gas price forecast methodology is consistent with MTEP's Continued Fleet Change and Distributed & Emerging Technologies scenarios. These scenarios use NYMEX Henry Hub pricing for the first two years and a blend of Wood Mackenzie and US Energy Information Administration forecasts thereafter. Fuel price risk was considered by including a high gas price scenario. Lower pricing scenarios were also evaluated. The reference case natural gas price increases at a compound annual rate of 5.3% per year ($2.80/MMBtu in 2019 to $7.85/MMBtu in 2039). This natural gas price growth is over 3% per year higher than that of coal price growth assumed in this study.

FUEL MIX AND RISK MITIGATION

Both a decision to continue to rely extensively on existing coal resources and one to move partially or completely away from coal carry financial risks. Maintaining a diversified fuel mix is often considered a prudent utility practice to reduce financial risk. In 2017, Dallman Station coal units provided 90% of CWLP's energy requirements. The majority of the remaining energy comes from market purchases. Energy from natural gas-fired resources is essentially negligible, and CWLP has no renewable generation or purchased power agreements.

On the other hand, depending primarily on market purchases opens up market risk, where cost to serve load is dependent on the fluctuating price of energy and the fluctuating price of natural gas. These risks can be mitigated by hedging the cost of spot-market energy. A utility with a large portion of its resource mix coming from market purchases could, and probably should, make forward purchases to reduce price risk.

Both of these risks can be mitigated by maintaining a balanced portfolio and resource mix. For example, a utility can rely on shares of thermal generation, renewable generation, and market purchases.