10.2 Justification for Exiting the IPP Repowering Project

RPU began examining the option of participating in the IPP repowering contract during the utilities 2014 Integrated Resource Planning (IRP) process. At that time, there were two primary motivating factors that staff believed might justify RPU's participation. The first was the potential to secure power from a natural gas generation facility at a cost slightly below a local tolling arrangement, and probably at a lower MW level than would otherwise be available from a local combined cycle natural gas (CCNG) plant. The second factor was the potential to retain excess transmission capacity on the Southern Transmission System (STS). This excess transmission could in theory be available for RPU to use to import future renewable or carbon free energy, or monetized in some other manner for the benefit of RPU rate-payers.

During the 2014 IRP process, staff examined the financial attractiveness of the IPP repowering option, based on the (very preliminary) cost factors available at that time. These analyses suggested that the repowering project should cost less than a local tolling option, provided all of the initial cost estimates were accurate. However, the monetizing of the excess STS capacity was not examined in these analyses. At the time of these studies, this excess STS capacity was viewed as a "free option" with little or no downside, and the costs for maintaining this transmission capacity had not yet been clearly defined.

Since these first studies were performed, the IPP repowering project has experienced a significant number of new developments. First, the CA participants have mutually agreed to retire the coal units two years ahead of schedule (i.e., by June 2025), thus accelerating the time line for the CCNG repowering project. However, the costs associated with this repowering project have steadily increased, even though the final configuration for the new natural gas generation asset is still being determined. Likewise, LADWP has now informed the CA participants that the STS DC line will require 1.2 to 1.3 <u>billion</u> dollars in transmission upgrades, and also that all participants will be expected to sign 50 year contract commitments for both the generation and transmission assets. Meanwhile, the state of California is moving aggressively to mandate a carbon-free grid by 2045 and the CAISO Board of Governors released a draft discussion paper in early 2018 proposing a natural gas "exit strategy" by 2030.

The two initial advantages of this repowering project (discussed above) led staff to initially recommend that RPU remain engaged in the contract negotiations. However, based on a multitude of events that have transpired over the last 12-18 months, staff has now identified no less than nine reasons for exiting this repowering contract. Each of these reasons is discussed in more detail below.

1. 50 Year Contract Commitment

A core requirement for participation in the repowering project is that each member must commit to a 50 year contract. However, this contract length is at least twice as long as the industry standard and imposes substantial risk on the member utilities, particularly the CA participants. It is very likely that California will legislatively mandate that nearly all carbon emitting, thermal generation assets cease operation on or before 2050, leaving the participants in this project with a stranded asset for 20 to 25 years before the contract expires.

2. Regulatory & Legislative Uncertainties

There are numerous regulatory uncertainties involved with building new thermal generation assets, even for assets built outside the state. This repowering project will require multiple SB 1368 filings, a NEPA review, an EIS/EIR, and potentially significant regulatory permitting for the proposed natural gas pipeline infrastructure. More importantly, bills have now been introduced in the CA state legislature that would require that all natural gas generation facilities interconnected to the CAISO cease operation by 2045 (which is in direct conflict with the 50 year contract discussed in #1 above). Power Resources staff carefully assesses every proposed generation project for both regulatory and legislative risks; staff considers the risk levels for this repowering project to be problematically high.

3. Generation Construction Cost Uncertainties

LADWP is the default lead agency overseeing the proposed generation and construction cost estimates. Although this study is designed to be transparent, Riverside does not have sufficient staff to maintain a high level of oversight on the process, or fully review the various cost drivers and cost uncertainties. Furthermore, each revised cost estimate has resulted in a higher $/MWh price for the anticipated generation energy. The most recent forecasted "all-in" bus-bar price for the generation energy is currently $53.65/MWh in 2025, excluding unforeseen gas infrastructure costs, STS transmission upgrade costs, and future carbon costs. This cost is already $15 to $20 higher than SP15 market price forecasts for the same time period (before adding in any of the excluded additional costs).

4. Natural Gas Infrastructure

To date, three different pipeline options have been studied for this project, with projected infrastructure costs ranging from $40M to $100M. However, all of these options may incur additional right-of-way acquisition costs. Additionally, LADWP foresees potential additional permitting hurdles and future cost uncertainties associated with all of the proposed options. Adding to this complexity is that various CA participants are proposing / advocating different ideas on fuel sourcing. Currently, there is no agreement amongst the participants for how to proceed on the natural gas infrastructure planning process.

5. Future STS Transmission Upgrade Costs

In addition to designing, permitting and building a new CCNG asset, the IPP repowering plan calls for major infrastructure upgrades and improvements to the STS DC transmission line. The preliminary cost estimate for these proposed upgrades is 1.2 to 1.3 <u>billion</u> dollars, with the costs to be shared proportionally amongst the participants. (RPU would be responsible for 5.3% of these costs.) In theory, these costs should be recoverable through the utilities TRR filing at FERC, but full cost recovery is not guaranteed. Nonetheless, all participants will need to begin paying for these transmission system upgrades before the repowering project is completed. Thus, RPU may experience a multi-year negative cash flow before recovering these costs through a modified TRR filing, in addition to the non-negligible risk of receiving less than 100% cost recovery through the FERC TRR filing process.

6. Unresolved Transmission Contracts

Additional transmission uncertainties are contract related. First, if RPU stays in the IPP repowering project then the utility will need to renegotiate a new Transmission Service Agreement (TSA) with LADWP. This TSA is needed to secure the last non-CAISO leg of the transmission path to the CAISO intertie point (through LADWP service territory). The costs for this new TSA are expected to be significantly higher than the current TSA that covers the existing IPP contractual agreement.

Second, RPU also currently has a TSA agreement with SCE for the CAISO leg of the transmission path; this TSA allows the City to file for approximately 10 million dollars a year of SCE imposed transmission costs (billed to Riverside from SCE and recovered in Riverside's TRR filing). However, this TSA contract is set to terminate in 2027 and SCE has indicated that they will not extend it (since Riverside is a PTO in the CAISO and thus has no need for this legacy transmission agreement). Hence, Riverside expects to lose this TSA even if the City remains in the IPP repowering contract.

7. Conflicting Operational Goals of Participants

Ever since this repowering project was initially proposed, the project participants have expressed conflicting operational goals for the plant. The Utah participants want to build a CCNG plant optimized for steady baseload operation. In contrast, the California participants (particularly the CAISO participants) are seeking to build a type of hybrid plant optimized for maximum dispatch and ramping flexibility. Unfortunately, it is proving to be very difficult to co-optimize these different operating characteristics, since the final operating characteristics significantly impact the ultimate plant design, gas scheduling strategy, and O&M cost allocation proposals. RPU staff believes that reaching consensus on this issue will be challenging at best, and may in turn lead to unanticipated contract disputes and/or an overall delay in the proposed project timeline.

8. Carbon Cost Uncertainties

Perhaps the single greatest risk associated with this project is the unknown future cost of carbon. Given the aggressive push towards carbon reduction by the state of California, it would seem fundamentally irresponsible for RPU to commit its ratepayers to a 50 year contract with a carbon emitting resource. Even a contract for half this length would represent a significant risk, given the uncertainty around future carbon costs. From a resource planning perspective, it should be noted that staff do not intend to analyze any tolling contracts with natural gas resources for contract lengths longer than 10 years in this IRP. Contracts in excess of 10 years simply carry too much future carbon price risk.

9. Decommissioning Costs

LADWP has already signed a contract with IPA to repower the IPP facility. It seems extremely unlikely that LADWP will break this contract, since they need to retain access to the Southern Transmission System (STS DC line) in order to continue receiving ~300 MW of renewable wind energy that they already have under long-term contract. Burbank and Glendale are motivated to stay in this repowering contract for similar reasons (i.e., access to LADWP transmission for renewable power).

In contrast, as a CAISO member RPU does not need this transmission path, as Riverside does not have any renewable contracts that depend upon access to the STS DC line. There is really no motivation for Riverside to remain in this repowering contract unless the contract is financially viable. This issue is important, because the cities that remain in the repowering contract must bear the majority of the costs for decommissioning the coal facilities (assuming that IPP is successfully repowered). Or equivalently, given that LADWP will almost certainly repower the facility in some manner, cities that opt out of the repowering contract simultaneously opt out of paying the majority of future coal plant decommissioning costs. This represents a significant, additional avoided cost benefit that Riverside could take advantage of by choosing to exit by 2019.

In summary, the IPP repowering contract no longer represents a financially viable option for RPU or Riverside rate payers. The fully loaded cost of this natural gas power will most likely exceed $70.00/MWh in 2025, once the expected typical production cost overruns, carbon cost component, and the potential for paying the LADWP OATT for transmission access are all factored in. Hence, it no longer appears plausible that the fully loaded costs of this repowering project will come in below what RPU would pay for a tolling contract with a local natural gas generation facility here in Southern California. Furthermore, the risk profiles of these two options are not even remotely comparable (i.e., a 10 year tolling arrangement versus a 50 year ownership model). Finally, the retention of capacity on the STS DC line appears to offer RPU few tangible benefits to counter-balance the new financial risks brought on by the need for 1.3 billion dollars in DC line upgrades. Thus, the two primary drivers for staff's original interest in this project have now become greatly diminished, while multiple new financial risks have simultaneously emerged.

For all of the above mentioned reasons, the RPU Power Resources division recommends that Riverside exercise its exit right under the IPP Repowering Agreement. Therefore, with respect to this current IRP process, staff has assumed that RPU will cease receiving power under this contract after June 2027. Staff has also assumed that the IPP coal plants will be decommissioned by June 2025 and that the final two years of reduced energy deliveries will originate from the (still to be built) CCNG facility. Note that additional details concerning these assumptions and forecasted portfolio cost impacts are presented in Chapter 13, respectively.