BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Amended Application of Boyd Gaming Corporation to purchase energy, capacity, and/or ancillary services from a provider of new electric resources.	))))	Docket No. 18-11039

At a general session of the Public Utilities Commission of Nevada, held at its offices on June 12, 2019.

PRESENT: Chairwoman Ann Pongracz
Commissioner C.J. Manthe
Commissioner Hayley Williamson
Assistant Commission Secretary Trisha Osborne

ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

I. INTRODUCTION

On November 28, 2018, Boyd Gaming Corporation ("Boyd") filed an Application with the Commission, designated as Docket No. 18-11039, to purchase energy, capacity, and/or ancillary services from a provider of new electric resources.

On January 24, 2019, Boyd filed an Amendment to the Application.

II. SUMMARY

The Commission grants the Amended Application, subject to the payment of an impact fee and the satisfaction of the compliances and directives delineated in this Order.

III. PROCEDURAL HISTORY

• On November 28, 2018, Boyd filed the Application. Boyd filed the Application pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC"), Chapters 703, 704, and 704B, including, but not limited to, NRS 704B.310, NAC 704B.310, and NAC 704B.340.

• The Regulatory Operations Staff of the Commission ("Staff") participates as a matter of right pursuant to NRS 703.301.

• On December 7, 2018, the Attorney General's Bureau of Consumer Protection ("BCP") filed a Notice of Intent to Intervene pursuant to Chapter 228 of the NRS.

• On December 10, 2018, the Commission issued a Notice of Application and a Notice of Prehearing Conference.

• On December 10, 2018, Tenaska Power Services Co. ("Tenaska") filed a Petition for Leave to Intervene ("PLTI").

• On December 27, 2018, Nevada Power Company d/b/a NV Energy ("NPC" or "NV Energy") filed a letter notifying the Commission that it would become a party in this matter pursuant to NAC 704B.310 and 703.595.

• On January 9, 2019, the Commission held a prehearing conference. Boyd, Staff, BCP, NPC, and Tenaska (the "Parties") all made appearances. At the prehearing conference, the parties made appearance and discussed Tenaska's PLTI, a procedural schedule, the handling of discovery disputes, and the Commission's review of 704B applications.

• On January 15, 2019, the Commission issued a Procedural Order establishing the procedural schedule for this Docket and an Order granting Tenaska's PLTI.

• On January 24, 2019, Boyd filed an Amendment to its Application ("Boyd's January 24, 2019, Amendment").

• On February 1, 2019, Staff filed its Final Impact Analysis as well as a Motion to Dismiss or in the Alternative Order Boyd to File an Amended Application ("Staff's First Motion").

• On February 8, 2019, NPC, BCP, and Boyd each filed Responses to Staff's First Motion.

• On February 11, 2019, the Commission issued Procedural Order No. 2, cancelling the February 12, 2019, continued prehearing conference.

• On February 15, 2019, NPC and Boyd each filed an Alternative Analysis, and Staff filed a Reply in support of its First Motion.

• On February 25, 2019, the Commission issued Procedural Order No. 3 and an Order on Motion denying in part and deeming moot in part Staff's First Motion.

• On February 28, 2019, the Commission issued a Notice of Hearing, and Boyd filed Prepared Direct Testimony.

• On March 8, 2019, the Commission held a conference call with the Parties to discuss discovery response timelines and issued Procedural Order No. 4 updating the discovery response timelines.

• On March 11, 2019, BCP, NPC, and Staff filed Prepared Direct Testimony.

• On March 15, 2019, the Commission issued Procedural Order No. 5 altering the procedural schedule in this Docket.

• On March 18, 2019, Boyd filed a Motion to Compel ("Boyd's Motion") and the Commission issued a Notice of Hearing.

• On March 20, 2019, BCP, NV Energy, and Staff filed responses to Boyd's Motion.

• On March 22, 2019, Boyd filed a Reply to the responses, the Commission issued Procedural Order No. 6 scheduling a prehearing conference in this Docket and deviating from the noticing requirements in NAC 703.160, and a Notice of Prehearing Conference.

• On March 25, 2019, Staff filed Revised Direct Testimony.

• On March 26, 2019, the Commission held a prehearing conference. The Parties all made appearances. At the prehearing conference, the Parties discussed Boyd's Motion, the timelines in this Docket, and Staff moved to update the statutory deadlines based on Boyd's January 24, 2019, Amendment.

• On March 26, 2019, the Commission issued Procedural Order No. 7 suspending the procedural schedule in this Docket.

• On April 3, 2019, the Commission issued an Order granting Staff's motion to update the statutory deadlines based on Boyd's January 24, 2019, Amendment.

• On April 8, 2019, the Commission issued Notice of Amended Application.

• On April 12, 2019, the Commission issued Procedural Order No. 8, updating the procedural schedule in this Docket, and a Notice of Hearing.

• On April 15, 2019, the Commission issued an Order on motion granting in part and denying in part Boyd's Motion.

• On April 17, 2019, BCP filed a letter advising that Dale Stransky would be adopting Jerry Mendl's testimony.

• On April 19, 2019, Boyd filed Prepared Rebuttal Testimony.

• On April 23, 2019, Staff filed Revised Prepared Direct Testimony.

• On April 24, 2019, BCP filed Revised Prepared Rebuttal Testimony.

• On April 26, 2019, NPC filed Corrected Prepared Direct Testimony.

• On April 29, 2019, the Commission held a hearing. The Parties all made appearances.

Pursuant to NAC 703.730, the Presiding Officer accepted Exhibits 1-21 and Confidential Exhibits C1-C15 into the record as evidence.

- On May 2, 2019, NPC submitted late-filed Confidential Exhibit C14 and corrected late-filed Exhibit No. 19.

- On May 14, 2019, NPC submitted corrected late-filed Exhibit No. 19.

IV. AMENDED APPLICATION

Boyd's Position

1. Boyd states that it notified Staff, BCP, and NPC of its intent to purchase energy, capacity, and ancillary services from a provider of new electric resources by issuing its letter of intent on October 9, 2018. (Ex. 1 at 2; Ex. 4 at 3.)

2. Boyd states that it is an "eligible customer" under NRS Chapter 704B. (Ex. 1 at 2; Ex. 4 at 3.) Boyd states that NRS 704B.080 defines an eligible customer as a "nongovernmental end use customer that has an average annual load of one megawatt or more in the service territory of an electric utility" and that NAC 704B.300 (2) requires each eligible customer's service location to have consumed 8,760,000 kilowatt-hours ("kWh") or more of energy in the service territory of the utility during the most recent 12-month period. (Ex. 1 at 2; Ex. 4 at 3.) Boyd states that each of its facilities that are the subject of this Application is a non-governmental commercial end-use customer in the service territory of NPC that annually consumes more than 8,760,000 kWh of energy at its contiguous property locations or at its service locations that are treated as a single service location for billing purposes. (Ex. 1 at 2-3; Ex. 4 at 3.)

3. Further, Boyd states that it is also an eligible customer pursuant to Section 1.13 (ii) of the NPC and Sierra Pacific Power Company d/b/a NV Energy ("SPPC") Open Access Transmission Tariff ("OATT"), which provides that an "eligible retail customer taking

unbundled Transmission Service pursuant to a Retail Access Program or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer and shall take service pursuant to Part IV of the Tariff." (Ex. 1 at 3-4; Ex. 4 at 3-4.)

4. Boyd states that it has selected Tenaska as its provider of new electric resources. (Ex. 1 at 4; Ex. 4 at 6.) Boyd states that it is still negotiating with Tenaska and that it expects a definitive agreement will be reached which, among other terms, will provide for the following: (1) obligate Tenaska to provide energy and capacity to Boyd, and (2) require Tenaska to comply with the applicable requirements of the renewable portfolio standard pursuant to NAC 704B.500. (Ex. 1 at 4-5; Ex. 4 at 6.) Boyd states that the agreement will be provided to the Commission pursuant to the requirements of NAC 704B.370(5). (Ex. 1 at 5; Ex. 4 at 6.)

5. Boyd states that it will purchase "new electric resources" as defined by NRS 704B.110. (Ex. 1 at 6; Ex. 4 at 8.) Boyd states that it will not take service directly from generation assets that are owned by or contractually committed to NPC and that, consistent with prior NRS 704B compliance items, Tenaska will develop and file a compliance policy subject to review and approval by the Commission. (Ex. 4 at 8.)

6. Boyd states that it will become an NPC Network Integration Transmission Service ("NITS") customer and will utilize Tenaska as its agent to manage the NITS services to facilitate delivery of power from the point of receipt to the point of delivery. (Ex. 1 at 6; Ex. 4 at 9.) Boyd states that it has begun the process of submitting its NITS application to facilitate the purchase of 37 megawatts ("MW") of energy, capacity, and ancillary services, as well as transmission services pursuant to the terms of the OATT. (Ex. 1 at 7; Ex. 4 at 9.) Boyd states that it will file the executed NITS with the Commission pursuant to the NAC 704B.370(1)(b) (Ex. 1 at 7; Ex. 4 at 9.) Boyd states that it will also execute a Network Operating Agreement

("NOA") with NPC. (Ex. 1 at 7; Ex. 4 at 9.) Boyd states that, upon execution, Boyd will file the NOA with the Commission pursuant to NAC 704B.370(1)(b). (Ex. 1 at 7; Ex. 4 at 9.) Boyd states that it will also file with the Commission an executed distribution service agreement as required by NAC 704B.370(1)(a). (Ex. 1 at 7; Ex. 4 a 9-10.)

7. Boyd states that it is in the process of transitioning its meters to time-of-use meters with the necessary communication systems as required by NAC 704B.340(1)(b) and that it will be completed with this process prior to taking service from Tenaska. (Ex. 1 at 7; Ex. 4 at 10.)

8. Boyd states that, pursuant to NRS 704B.320, it will obtain the required contractual rights for an additional amount of energy equal to 10 percent of the total amount of energy that Boyd is purchasing for its own use under the proposed transaction and the capacity and ancillary services associated with the additional amount of energy (the "10-percent contract.") (Ex. 1 at 7; Ex. 4 at 11.)

9. Boyd states that Staff's Final Analysis overstates Boyd's impact fee and that certain adjustments need to be made to Staff's analysis. (Boyd Alt. Analysis at 1; Phillips at 14.) Boyd states that Staff's final analysis did not use the October 1, 2019, commencement date and that it did not credit Boyd with the off-system sales ("OSS") margins that NPC expects to realize as a result of remarketing generation formerly used to serve Boyd. (Ex. 3 at 1.)

10. Boyd states that it had a discussion with BCP, NPC, and Staff which culminated in the parties agreeing that there was an error in the portion of the regulatory asset component of the impact calculation. (Ex. 6 at 16.) Boyd states that NPC sent out an updated impact analysis correcting this error, but it was too late for Staff to include it in its analysis. (*Id.*) Boyd states

that one month of energy efficiency impact needed to be removed from the analysis due to the change in commencement date. (*Id.* at 17.)

11. Boyd recommends that it be credited with 100 percent of the OSS revenues estimated by PROMOD. (*Id.* at 18.) Boyd states that the OSS net revenues were calculated using the same production costing methodology and system modeling that was used in all previous 704B applications. (*Id.*)

12. Boyd states that in all fully-litigated 704B dockets between January 1, 2014, and February 20, 2019, the Commission ordered the applicant to be credited with 100 percent of the OSS revenues resulting from the utility no longer serving the departed customer. (*Id.* at 19-21.)

13. Boyd states that in the past, Staff has made statements supporting the inputs used in PROMOD and that NPC has been using PROMOD for years to conduct production cost simulations supporting its core operations and integrated resource planning ("IRP"), and has made numerous public statements supporting PROMOD. (*Id.* at 21-23.) Boyd states that it believes that PROMOD accurately and reliably projected OSS revenues associated with a 704B applicant's potential departure from NPC's system. (*Id.* at 24.)

14. Boyd states that in order to determine OSS specifically attributable to a particular customer exiting the retail system, two sets of data are needed: (1) what would have happened if the customer had remained a part of the system; and (2) what happened after the customer exited the retail system, keeping all other variables equal. (*Id.* at 25.) Boyd states that this is what the PROMOD cost simulations are able to do, with the only difference being that PROMOD does not look at historical data but instead estimates what will happen. (*Id.* at 25-26.)

15. Boyd states that it agrees with Staff's testimony in Docket No. 18-08007, that simply looking at an annual Federal Energy Regulatory Commission ("FERC") Form 1 is not

enough to determine sales attributable to a 704B customer. (*Id.*) Furthermore, Boyd states that, similar to the now-abandoned net-BTER true-up, a counterfactual analysis is extremely difficult to perform and would require PROMOD to simulate realities that did not actually occur. (*Id.* at 26.)

16. Therefore, Boyd recommends that it receive the full OSS credit estimated by PROMOD because PROMOD impact estimates are a reasonably forecasted revenue impact to the utility and remaining customers that already control for the numerous variables that change from year to year, and Boyd states that there has been no evidence presented by any party that the PROMOD runs are unreliable. (*Id.* at 26-27.) Furthermore, Boyd states that, consistent with past Commission 704B decisions to do away with the net-BTER true-up and focus on a snapshot-in-time revenue impact, Boyd recommends that the Commission create no additional true-ups or other regulatory burdens. (*Id.* at 27.)

17. Boyd states that Staff did not provide any data, analysis, rationale, or evidence in its Final Analysis in support of Staff's position to not give the OSS credit to Boyd. (*Id.* at 27-28.)

18. Boyd states that granting the OSS credit is the only fair and non-discriminatory way to perform the impact fee calculation. (*Id.* at 29.) Further, Boyd states that Staff's directive to remove all placeholder resources from PROMOD in the analysis actually understates OSS because that assumption causes more of NPC's retail load to be served by market purchases. (*Id.*) Therefore, Boyd states that, in order to ensure that the impact fee paid by Boyd is non-discriminatory between Boyd and remaining customers, and because it is being asked to pay 100 percent of the estimated increase in BTER-related costs that remaining customers are forecasted to incur, Boyd should receive 100 percent of the estimated benefits that the system is forecasted to realize as a result of Boyd's departure. (*Id.*)

19. Boyd states that it is not seeking certain adjustments to Staff's Final Analysis because these adjustments have not been awarded to other recent and similarly-situated 704B applicants. Boyd states that the Commission should view the legitimate adjustments that Boyd is not seeking as additional assurance that the remaining ratepayers will not bear increases in costs. The adjustments that Boyd is not seeking are: (1) credit with the incremental transmission revenues generated by the incremental OSS volumes determined by PROMOD to be economic; (2) credit for its marginal cost of service study revenue-based share of impact fees ordered by the Commission and paid by MGM, Wynn, Caesars, Station, and Georgia-Pacific Gypsum that are not currently reflected in rates; (3) an adjustment to Boyd's load used to determine its impact fee to reflect normal weather; and (4) an adjustment related to the balance of excess accumulated deferred income taxes ("ADIT") created by the Tax Cuts and Jobs Act ("TCJA") (*Id.* at 30-36.)

20. Boyd states that the project identified by Staff's First Motion contemplates a possible expansion of the Fremont Hotel and Casino ("Fremont"). (Ex. 5 at 5.) Boyd states that its internal timeline contemplates the expansion coming online approximately 30 months after ground breaking, but that some of that schedule is outside of Boyd's control. (*Id.*) Boyd states that it has taken certain steps in anticipation of its Board considering moving forward with the expansion, including: (1) preparing drawings of the potential expansion; (2) engaging in Rule 9 discussions with NV Energy; and (3) obtaining local government approvals necessary to facilitate the expansion, such as approval of its Development Plan from the Las Vegas Planning Commission and the Las Vegas City Council. (*Id.* at 5-6.) Boyd states that it generally seeks local entitlement approvals, including the maximum entitlements necessary, before presenting a possible expansion to its Board for approval. (*Id.* at 6.) Boyd states that just because the

maximum entitlements are sought and obtained does not indicate that the related project will move forward at all or at any particular scope. (*Id.*)

21. Boyd states that its Board is charged with the decision to approve, disapprove, or modify the Fremont project and can limit the scope of whatever proposal is put forth. (*Id.* at 7.) Boyd states that the Board has not approved the Fremont expansion and that there is no Board meeting scheduled for the presentation of the proposed expansion. (*Id.*) However, Boyd states that the timeline for the presentation to happen is currently being developed with the objective being that the proposed project be presented to the Board no later than the end of this calendar year. (*Id.*)

22. Boyd states that it cannot state with certainty what the potential for the Fremont expansion to go forward is or if the Board will approve the Fremont expansion. (*Id.* at 8.) Further, Boyd cites the Echelon project as a project on a larger scale than Fremont that was stopped mid-project. (Tr. at 20.)

23. With respect to the Fremont expansion's effect on the impact fee, Boyd states that NPC did not include the expansion in its alternative analysis, and Boyd speculates that the lack of inclusion is because NPC has not been planning for the load. (Ex. 6 at 36-37.) Furthermore, Boyd states that it reviewed the IRP in Docket No. 18-06003 and prior IRPs and IRP updates and that there is no mention of the Fremont expansion. (*Id.* at 37.)

24. Boyd states that if NPC has not planned for the expansion, then it should not be included in the impact fee because it would be contrary to the stranded cost analysis that the Commission has employed in evaluating 704B Applications. (*Id.*) Further, Boyd states that, as it relates to NPC's planning function, the Fremont expansion is similar to a 704B applicant who

has never been a customer of NPC and that the Commission has refused to impose impact fees on such customers. (*Id.*)

25. Boyd states that the Fremont expansion should not be included in the impact fee but that if the Commission chooses to include it, the Commission should make it clear that the non-bypassable charges should not be applied to the expansion load, as the legacy costs that the non-bypassable charges recover were incurred long before the Fremont expansion was ever contemplated. (*Id.* at 38.) Boyd states that if the expansion is included in the impact analysis, it would reduce the upfront portion of Boyd's impact fee by $357,000 because it would not be complete until January 2021 at the earliest, and beginning in 2022, removing the load from the system reduces overall system costs, meaning that the Fremont expansion would only have one year where it increases costs and almost four years where it reduces costs. (*Id.* at 38-39.)

26. Boyd states that if the Commission does not include the Fremont expansion in the impact fee, it should make it clear that Boyd can have the expanded portions of Fremont served by its provider of new electric resources. (*Id.* at 40.) Boyd states that because the expansion has not been planned for by NPC, there would be no need to file a new 704B application. (*Id.*)

27. Boyd states that, similar to Docket No. 18-08007, the Commission should consider the possibility of applying a credit to Boyd in the event of a delay in Boyd's commencement date. (*Id.* at 42.)

28. With respect to the transition to being a distribution-only service ("DOS") customer, Boyd states that it has engaged the utility in planning with respect to meter requirements and installations but that it is too early to say if the October 1, 2019, commencement date is reasonable. (Tr. at 9-10.) Boyd states that it is still determining the individual vendors for the meters and that the meters have not been ordered yet. (*Id.* at 10.)

Further, Boyd states that it is not prepared to order the equipment without a decision from the Commission on this Amended Application and a reasonable impact fee. (*Id.* at 10-11.) Boyd also states that without a decision in this docket, it is possible to meet with the utility to discuss original and conceptual design, which would then be followed by ordering the equipment, that there are other activities that need to be engaged in absent the ordering of meter equipment, and that Boyd selected its transition date with those activities and actions in mind. (*Id.* at 11.)

NPC's Position

29. NPC states that in examining NRS 704B applications, the Commission is tasked with protecting the electric utilities in this State and their remaining customers. (Ex. 12 at 4.) NPC states that remaining customers must not be subject to increased costs as a result of an NRS 704B transaction and that the transaction must not be contrary to the public interest. (*Id.*) Further, NPC states that NRS 704B applicants bear the responsibility to demonstrate that the proposed transaction is not contrary to the public interest. (*Id.* at 6.)

30. NPC states that NRS Chapter 704B was established when the energy market for Nevada and the western United States was quite different, including supply shortages and high prices for electricity. (*Id.* at 6-7.) Currently, NPC states that it is not dependent on regional energy markets, the energy markets in the western United States are not viewed as "dysfunctional," and eligible customers are not proposing to develop new generation resources within the Nevada balancing area authority. (*Id.* at 7.)

31. NPC appears to argue that Boyd has not made an adequate showing that the proposed transaction is in the public interest because Boyd relies on Commission decisions in past 704B applications to justify its Application. (*Id.* at 8.) NPC states that past Commission decisions have noted that administrative agencies are not bound by *stare decisis* and that

applying the same analysis in this case as the Commission did in past cases would result in *ad hoc* rulemaking in violation of NRS 233B. (*Id.* at 8-9.)

32. NPC states that, if the Commission finds that Boyd's proposed transaction is not contrary to the public interest, then the Commission should establish the Base Tariff General Rate ("BTGR") impact using a 10-year period and the net-Base Tariff Energy Rate ("Net-BTER") impact using a 6-year period. (*Id.* at 9.) Additionally, NPC states that the Commission should modify Staff's "lump sum" analysis by requiring Boyd to pay a non-bypassable Renewable-BTER ("R-BTER") and temporary renewable energy development ("TRED") charges for the lives of the underlying contracts. (*Id.*)

33. NPC states that it also made the following changes to Staff's impact analysis: (1) updating Boyd's departure date to October 1, 2019; (2) including placeholder generation units in the production cost modeling that were used in the IRP; and (3) a correction to the model where existing regulatory assets were removed from the impact fee calculation. (Ex. 10 at 3-4.) NPC states that, based on these changes, the impact fee is $18,056,000. (*Id.* at 4.)

34. NPC states that a 10-year period for the BTGR component of the impact fee is appropriate because the Commission can no longer assume that NPC will have steady load growth to offset the impact of Boyd no longer being a fully-bundled customer due to the Commission's recent order in Docket No. 18-06009, and a number of existing large customers expressing interest in filing an NRS 704B application. (Ex. 12. at 9.) NPC states that it believes that the Commission's order in Docket No. 18-06009 will impact future load growth in its large commercial and industrial class because the Order found that new businesses to Nevada do not have to pay an impact fee or non-bypassable charges because they were not specifically planned

for in load forecast. (*Id.* at 9-10.) NPC states that this 10-year period increases Staff's recommended impact fee by $6,046,000. (Ex. 10 at 4.)

35. With respect to the BTER component of the impact fee, NPC states that the Commission should use the "net" methodology recommended by Staff, but limit the analysis period to six years because the methodology recommended by Staff uses simplifying assumptions by removing placeholders and, therefore, does not accurately reflect prudent resource planning principles and results in too much reliance on wholesale energy markets. (Ex. 12 at 10.)

36. NPC states that this risk is evidenced by the $1,662,250 reduction in the impact fee caused by Boyd changing its commencement date from September 1, 2019, to October 1, 2019. (*Id.* at 10-11, Ex. 10 at 4-5.) NPC states that there is a drastic change in the impact fee due to the removal of a high-cost summer month in the beginning of the exit fee period and replacing it with one with future costs discounted to current-year values. (Ex. 10 at 4-5.) Therefore, NPC recommends that the Commission use a six-year period for the net-BTER impact and that the Commission use non-bypassable R-BTER and TRED charges to extend for the lives of the contracts, rather than the six years recommended by Staff because the cost of these long-term contracts will extend well beyond Boyd's transition to DOS service. (Ex. 12 at 11.)

37. NPC states that the R-BTER is the portion of the BTER that represents the costs for "out of the money" renewable energy power purchase agreements that NPC entered into to ensure compliance with Nevada's renewable portfolio standard ("RPS"). (Ex. 9 at 2.) NPC discusses contracts that were included and excluded from the R-BTER calculation, pursuant to Staff's directive, and discusses that Staff requested that the base analysis be the resource plan proposed in 18-06003. (Tr. at 136-40.)

38. NPC states that, if Boyd chooses to make a single, present-value payment at the time it transitions to distribution-only service, then NPC should not pay carrying charges on the BTGR, Emissions Reduction and Capacity Replacement ("ERCR") regulatory asset, and Non-ERCR regulatory asset components of the impact fee because such a payment would burden NPC with increased costs and is therefore contrary to the public interest. (Ex. 12 at 11-12.) NPC states that past Commission orders have found that if the applicant chooses to make a single, present-value payment, then NPC must incur carrying charges on the "unamortized balance of these components which will be reflected in rate base in [its] next general rate case from the point the impact fee is paid." (*Id.* at 12-13.) NPC states that, while it receives an infusion of funds when a customer makes a single, present-value payment, NPC's rate of return (the carrying costs) exceeds the overnight bank funding rate and other options for cash investment. (*Id.* at 13.) NPC states that as of March 8, 2019, there was a five-percent gap between the rate at which NPC accrues interest and the likely option for cash investments, which puts upward pressure on expense. (*Id.*)

39. NPC states that its production cost analysis departed from Staff's directive by evaluating the open capacity position and developing placeholders to address compliance with the RPS and to include conventional resource placeholders to address system capacity requirements in a manner consistent with integrated resource planning principles. (Ex. 11 at 3.) NPC states that the production costs reflect an economically efficient use of available resources, including NPC-owned generation, contracted generation, and market purchases to meet the needs of customers under different load forecast scenarios. (*Id.* at 3-4.) NPC states that it included placeholders in its alternative analysis because without them, production cost analysis leads to BTER projections that unrealistically rely on the wholesale markets for the purchase of energy

and capacity and do not comply with NPC's approved energy supply plan ("ESP") and integrated resource planning philosophy. (*Id.* at 4.) NPC states that the incorporation of these placeholder units increases Boyd's impact fee by $260,000 relative to Staff's analysis. (Ex. 10 at 5.)

40. NPC states that its analysis also incorporates a correction to the regulatory assets included in the calculation of the impact fee, and this correction lowers the total impact fee by $602,000 when considering a transition date of October 1, 2019. (*Id.* at 5-6.)

41. Additionally, NPC states that Boyd used inaccurate figures for TRED, the renewable energy program rate ("REPR"), and SB123 liabilities in calculating its lump-sum model and that correcting these inaccurate figures results in a total non-bypassable liability of $9,793,000. (Ex. 10 at 8.) NPC states that Boyd applies a TRED rate of $.00066 to Boyd's sales, while the current TRED rate is $.00067. (*Id.*) Additionally, NPC states that the TRED rate will be updated to $.00068 on October 1, 2019, and that this figure should be used as it coincides with Boyd's departure. (*Id.*) NPC states that Boyd also uses an incorrect load-ratio share for Boyd in its lump-sum model and that this appears to be an input that was not updated for a lump-sum model used for Station Casinos in Docket No. 18-06008. (*Id.*) NPC states that it is not aware of any statutory basis for why the REPR could not be charged to DOS customers. (Tr. at 144.)

42. NPC states that it did not include OSS in its analyses because forecasting OSS months and years into the future is speculative and therefore not appropriate for inclusion in an impact fee assessment. (Ex. 11 at 4.) NPC states that forecasting OSS is speculative because the wholesale markets are dynamic in nature and are influenced by factors such as generator availability, natural gas supply, transmission availability, and weather conditions. (*Id.* at 5.)

43. NPC states that its ability to execute OSS is affected by policies put into place to comply with NRS 704B.110, including restrictions that are communicated to power traders and electricity brokers to mitigate the potential for human error in buying electricity from NV Energy for serving a 704B customer. (*Id.*) Furthermore, NPC states that providers of new electric resources also have put restrictions into place to ensure that they do not buy energy from NV Energy. (*Id.*) NPC states that these counterparty restrictions reduce the pool of willing buyers of electricity from NV Energy and reduce the opportunity to execute OSS for the benefit of retail customers. (*Id.*) NPC states that, while the Energy Imbalance Market ("EIM") has provided a benefit to retail electric customers in the form of access to a lower cost of energy supply, it has resulted in fewer opportunities to economically sell energy generated using natural-gas-fired resources. (*Id.* at 6.)

44. Additionally, NPC states that there are several reasons why it cannot optimize capacity freed up by departing customers, including: (1) it seems implausible that NPC can generate substantial amounts of revenue by selling into the same market that will allow 704B customers to save money purchasing energy; (2) NPC optimizes its daily resources for the benefit of native load customers, so any additional opportunities created by 704B transactions in the day-ahead and hour-ahead energy markets are minimal at best; and (3) with reduced load requirement, sometimes the most economic action is to put generators into economic reserve shutdown. (*Id.* at 6-7.) NPC states that growth in renewable energy production in the western United States has put downward pressure on the wholesale price of electricity, which enables NPC to reduce fuel and purchased power costs through economic shutdowns of natural gas and coal-fired resources in favor of purchased power. (*Id.* at 7.)

45. NPC states that the transition of a customer to DOS would decrease NPC's open position in the summer months and create a longer position in non-summer months with a closed position. (Ex. 7 at 5.) However, NPC states that there has been no increase in forward sales activity due to having a longer position in the non-summer months. (*Id.*) Further, NPC states that the market value of additional forward capacity is minimized by lower regional loads and competing regional supply causing NPC's generation resources to be non-competitive in the non-summer months. (*Id.*) NPC states that forward capacity sales represent less than one percent of its total OSS since 2015. (*Id.* at 5-6.)

46. With respect to month-ahead sales, NPC states that between 2014 and 2018, it issued a total of 45 Reverse Requests for Proposals ("RRFP") and that of the 45 RRFPs issued, only three resulted in forward sales transactions where the cost to serve the sale was projected to produce an economic benefit to customers at the appropriate confidence levels. (*Id* at 6.) NPC states that, based on counterparty responses to date, it does not anticipate that forward sales will substantially increase. (*Id.* at 7.)

47. Additionally, NPC states that, on a daily basis, it compares owned energy costs to market prices in order to identify and capture opportunities for mitigating the cost of providing electric service to native load customers. (*Id.*) NPC states that it has not observed any incremental off-system wholesale sales attributed to 704B applicants becoming DOS customers. (*Id.* at 8.) NPC states that it reviewed its OSS volumes from 2014 to 2018 and found that the changes in sales volumes do not appear to increase consistent with 704B applicants becoming DOS customers. (*Id.* at 8-9.) Instead, NPC states that the changes in volume likely reflect variations in market conditions, including, but not limited to, available regional supply, weather conditions, transmission congestion and availability, and renewable resource production. (*Id.* at

8.) Additionally, NPC notes that 2018 was the first year that MGM, Caesars, Switch, and Wynn had departed bundled utility service and is the year that would best reflect the effect of 704B departures on OSS activity as the above-named entities totaled about 315 MW or 10 percent of NPC's load. (Tr. at 121-23.)

48. Further, NPC explains that when it optimizes resources, it focuses on optimizing resources to serve remaining customers and not on serving remaining customers and making OSS. (Tr. at 66-68.) NPC also explains that resources selling into the EIM have been put on line for the benefit of native load customers. (*Id.* at 64-65.)

49. NPC states that it has not determined how many sales were due to customer transitions and that it is unaware of any analysis that could make that determination because the transaction decision does not contemplate hypothetical scenarios such as how a sale would have been otherwise served with additional load from transitioned DOS customers. (*Id.* at 9.) NPC states that it is not practical or of any optimization value to perform such an evaluation in advance of every sales transaction. (Ex. 7 at 8.)

50. With respect to Boyd's arguments that the PROMOD estimates should not be ignored because PROMOD uses Commission-approved inputs and protocols, NPC notes that the Commission's IRP orders do not typically include explicit approval of modeling protocols, and if NV Energy was seeking to have a change of methodology approved, it would be in the application and prayer for relief. (Tr. at 125-27.) NPC states that the negative load control was not part of the last IRP application. (*Id.* at 126-27.) NPC also states that it has no issues with the way PROMOD is used to calculate BTER. (*Id.* at 124.)

51. NPC states that, while Boyd claims that the inclusion of the Fremont Project would reduce the impact fee due to OSS credits, the removal of those credits would increase the

impact fee as it is additional load. (Ex. 10. at 10.) NPC states that because the Fremont Project is an expansion of an existing site, it is appropriate to assume that its energy consumption patterns will be similar to existing patterns. (*Id.*) Therefore, NPC states that if the Commission decides to include the Fremont Project in the impact fee, and deems that additional analysis is not required, then the ultimate impact fee can be used to develop a rate that is applied to future Boyd sales for a period of time as determined by the Commission. (*Id.*) Boyd states that this would incorporate any changes in loads experienced by Boyd due to Fremont and would equate to a rate of $7.80/mega-watt hour ("MWh") or $7.93/MWh when using NPC's or Staff's alternative analysis, respectively. (*Id.*)

52. NPC states that it is unaware of any generation or energy-related planning that it may have undertaken in anticipation of the Fremont expansion. (Tr. at 83-84.) However, NPC states that: (1) the Fremont load is the type of load that would have been included in the generic model-based quantitative load forecast that was included in the IRP update; (2) NPC has begun to incur costs based on serving the load growth contemplated in the IRP action plan window through forward fuel procurements; and (3) the load should be included in the impact fee. (*Id.* at 133-36.)

BCP's Position

53. BCP recommends that the Commission: (1) grant Boyd's Application, subject to the $10.751-million impact fee calculated by Staff, which was calculated using the same methodology as in past 704B decisions[1]; (2) not grant Boyd any credit for OSS; (3) consider the potential Fremont expansion in the determination of the impact fee in the same manner it would consider a new customer; (4) not accept Boyd's or NPC's alternative analyses or modifications

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[1] BCP notes that the collective impact of the 704B departures may have impacts to remaining customers that are not captured by the current method of analysis. (Ex. 13 at 3.)

to Staff's impact fee, with the exception of providing no credit for OSS in NPC's analysis; (5) require Boyd to pay its share of legislatively-mandated charges, the Commission's annual assessment, and the local government franchise fee; and (5) accept Staff's recommendation to hold Boyd accountable for any potential costs associated with the retirement, decommissioning, and remediation of the Reid Gardner and Navajo generating stations and adjust Boyd's impact fee as needed based on the excess accumulated deferred income tax which is to be addressed at the next general rate case. (Ex. 13 at 2-5.)

54. BCP states that it agrees with Staff that no OSS credit should be provided to Boyd. (*Id.* at 6.) BCP notes that, in Docket No. 15-05017, the Commission, in granting an OSS credit, assumed that there were unknown and unquantified benefits and that those unquantified benefits, together with OSS, were reasonably estimated to be equal for the PROMOD calculated OSS. (*Id.*) Further, BCP states that the Commission did not find that the PROMOD calculation for OSS was accurate; rather, the Commission found that it provided a reasonable proxy for OSS and EIM sales. (*Id.* at 6-7.)

55. BCP states that it is improbable that the modeled levels of OSS would actually occur because NPC does not have a significant or sustained market advantage to sell power and because there has been no identifiable historical correlation between OSS and 704B customer departures increasing the amount of power available to sell. (*Id.* at 7.) BCP states that granting an OSS credit to Boyd shifts the risk of OSS not taking place to ratepayers. (*Id.*) BCP notes that under normal circumstances, bundled customers benefit when an OSS takes place, as the revenues reduce the revenue requirement, and they suffer no harm when no OSS takes place. However, if an OSS credit is granted to Boyd, then the impact fee is reduced, depriving bundled customers of the benefit of that part of the impact fee, and guaranteeing Boyd benefits,

regardless of whether OSS occurs, while bundled customers will not break even unless the OSS occurs. (*Id.*) BCP argues that the 704B customer should bear the risk associated with the OSS, as the customer is voluntarily departing bundled service. (*Id.* at 8.)

56. BCP states that it determined that actual OSS volumes are likely to be less than recommended based on the following: (1) NPC has not been able to identify a correlation between OSS and 704B departures; (2) forward power sales have been minimal due to economics and the lack of a consistent and significant market advantage; (3) NPC is a net purchaser in the markets that PROMOD is capable of modeling; (4) NPC is a net purchaser in the five-minute EIM; and (5) PROMOD overstates OSS because it assumes a perfect market with unlimited willing counter-parties. (*Id.* at 8-9.)

57. BCP states that NPC's response to a BCP data request confirms that NPC has not identified any sales increases attributable to 704B customer departures. (*Id.* at 9.) BCP notes that while this statement does not prove that there were no increased sales attributable to 704B departures, it does suggest that any sales were not notable. (*Id.*) BCP states that this response was not surprising, as NPC does not appear to have a significant or consistent market advantage to sell power over other utilities, meaning that even if NPC has surplus power to sell as a result of departures, more sales are not likely to be transacted. (*Id.* at 9-10.)

58. BCP states that NPC's forward sales program has only accepted a few offers since its inception, mostly because market conditions were such that the bids could not guarantee that NPC would not lose money on the transaction. (*Id.* at 10.) BCP states that the lack of acceptable bids is primarily due to the fact that NPC's efficient combined cycle units are too similar to other neighboring utilities, meaning that NPC has no market advantage, and because of the recent increase of transmission prices in the south, after which NPC indicated that it has a