

**ADMINISTRATOR'S
DECISION**

**IMPLEMENTATION OF THE FY 2018
SPILL SURCHARGE**

June 2018



IMPLEMENTATION OF THE FY 2018 SPILL SURCHARGE

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IMPLEMENTATION OF FY 2018 SPILL SURCHARGE

1. Introduction

The Spill Surcharge, Appendix C of Bonneville Power Administration's (Bonneville) 2018 Power Rate Schedules and General Rate Schedule Provisions, was established in the BP-18 rate proceeding.¹ Pursuant to Appendix C, Bonneville must calculate and, if appropriate, implement the Spill Surcharge for Fiscal Year (FY) 2018.

The Spill Surcharge is a formula rate adjustment that approximates the additional cost that power customers would have been charged if Bonneville had known planned fish passage spill operations when setting final BP-18 rates. It is calculated independently for each year of the FY 2018–2019 rate period based on planned spill operations for each year.

This document contains the decision of the Bonneville Administrator to implement the Spill Surcharge in an amount of \$10.2 million for FY 2018, a rate of 0.71 mills per kilowatthour for June–September 2018, and an annual rate of 0.23 mills per kilowatthour. A preliminary proposed surcharge was made available to customers and interested parties on May 8, 2018, for their review and comment. This decision document addresses the comments on the preliminary proposal received from customers and interested parties. This document also describes the statutory, procedural, and broader financial context for the decision implementing the FY 2018 Spill Surcharge and describes the calculation of the Spill Surcharge Amount and rates for FY 2018.

2. Background

Bonneville is a not-for-profit Federal power marketing administration, selling cost-based electric power and transmission services at wholesale, primarily to the public bodies and cooperatives that serve domestic and rural consumers in the Pacific Northwest. Under its four enabling statutes,² Bonneville must balance multiple public duties and purposes in providing these services, including: assuring the Pacific Northwest of an adequate, efficient, economical, and reliable power supply; acquiring energy conservation and the development of renewable resources consistent with the plan; and, consistent with the program developed by the Northwest Power and Conservation Council, protecting, mitigating, and enhancing fish and wildlife in the Columbia River Basin that are affected by the development and operations of the Federal hydroelectric projects from which Bonneville markets power.

Unlike most Federal agencies, Bonneville does not receive annual congressional appropriations; instead, Bonneville is self-financed from revenues received from the sale of power and transmission services. Bonneville utilizes this revenue not only to pay for the continuing costs associated with its programs (including power, transmission, and fish and wildlife, among others), but also to repay the United States Treasury for the power share of the original Federal

¹ See BONNEVILLE POWER ADMIN., ADMINISTRATOR'S FINAL RECORD OF DECISION, 62-104 (July 2017), <https://www.bpa.gov/Finance/RateCases/BP-18/bp18/Final%20Proposal/BP-18-A-04%20Final%20ROD.pdf>.

² 16 U.S.C. §§ 832-832m (Bonneville Project Act); 16 U.S.C. §§ 837-837h (Regional Preference Act); 16 U.S.C. §§ 838-838I (Federal Columbia River Transmission System Act); 16 U.S.C. §§ 839-839h (Pacific Northwest Electric Power Planning and Conservation Act, commonly known as the Northwest Power Act or NWPA).

investment used to construct the Federal Columbia River Power System (FCRPS).³ The Bonneville Administrator establishes and revises power and transmission rates to be as low as possible and recover its costs consistent with “sound business principles.”⁴ Bonneville’s rates enable the agency to make timely repayments to the Treasury and simultaneously fulfill multiple public purposes for the benefit of the Pacific Northwest. In other words, Bonneville operates like a business, not to generate a profit, but to provide public-purpose benefits to the region.

In order to sustain its ability to provide these services, Bonneville must maintain its commercial viability in the face of significant changes occurring in the electric utility industry and in particular the western energy market. These include a steady decline in spot market prices on the west coast as a result of the development of renewable energy resources that are contributing to an oversupply of energy and shifts in peak and off-peak energy patterns, as well as new resource extraction technologies that are driving down the price for natural gas nationwide. Bonneville’s historical power customers have unprecedented economic choice in their power supply, and the market competition to supply these customers is increasing as more renewable generation is built and load growth remains flat to minimal.

Pursuant to the Pacific Northwest Electric Power Planning and Conservation Act (NWPAA), 16 U.S.C. §§ 839-839h, Bonneville enters into long-term contracts with its statutory preference customers,⁵ which provide that customers will pay the rates established by Bonneville during the period of those contracts. Over the last eight years, increasing cost pressures and depressed power sales revenue have led to four consecutive power rate increases for Bonneville’s preference customers, totaling more than 31 percent.⁶ This trend has occurred during a period in which preference customers are contractually obligated to continue purchasing power at Bonneville’s costs, but their current 20-year contracts expire in 2028. Should customers reduce or eliminate the power they purchase from the FCRPS, Bonneville’s ability to maintain revenue certainty would be at risk and threaten Bonneville’s ability to meet its multiple public-purpose responsibilities.

³ Bonneville is responsible for funding the “power share”—the proportion of the multiple designated purposes of the dams considered to be power-related—of the total project investment costs and ongoing operations and maintenance costs of the Federal projects that comprise the FCRPS. The power share is determined as part of each individual dam and reservoir project’s authorization process and is derived from an analysis of the benefits from all of the project’s congressionally authorized purposes (*e.g.*, power generation, flood control, irrigation). Bonneville is responsible for 100 percent of all power-specific costs and the power share of all joint costs, such as fish costs, for each project. For the 14 Federal projects that are the subject of the ongoing litigation in *Nat’l Wildlife Fed’n v. Nat’l Marine Fisheries Serv.*, No. 3:01-cv-0640-SI (Dist. Or.), the average power share of joint costs is approximately 84 percent. BONNEVILLE POWER ADMIN., BP-18 FINAL RATE PROPOSAL, STATEMENTS A–F, F-6 (July 2017), <https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14647584>.

⁴ 16 U.S.C. §§ 839e(a)(1), 825s, 838g.

⁵ Bonneville’s preference customers are “public bodies and cooperatives.” 16 U.S.C. § 832c(a). They range from small rural electric cooperatives to large municipal utilities. 16 U.S.C. § 832b. Whenever they request, Bonneville is obligated to offer a power supply contract. *See* 16 U.S.C. § 839c(b)(1).

⁶ *See* BONNEVILLE POWER ADMIN., U.S. DEP’T OF ENERGY, INTEGRATED PROGRAM REVIEW 2: CLOSE-OUT REPORT, APR. 2017, 12-18 (2017) (July 2017), <https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/2016IPRDocuments/2016-IPR%202-Close-Out-Report.pdf>.

To continue serving as the provider of choice for long-term power supply in the region in 2028 and beyond, Bonneville must remain cost-competitive in this evolving marketplace. In light of concerns about the effects of market developments and other factors on Bonneville's long-term financial health, Bonneville launched a regional public process in 2015 to define and manage these risks.⁷ As an outgrowth of this process, Bonneville has taken a number of key steps designed to improve its long-term financial condition, including modernizing its governance structure, finding new market opportunities, and initiating a disciplined long-term cost management process in consultation with experts in the field.⁸

In addition to these key steps, Bonneville developed a Strategic Plan (issued January 2018) and a Financial Plan (issued February 2018). Together, the Plans provide an important guiding framework for how Bonneville will maintain and strengthen its financial health. The first goal of the 2018–2023 Strategic Plan is to strengthen financial health with a focus on improving cost-management discipline and building financial resiliency.⁹ The Strategic Plan outlines an objective to hold program costs, by business line, at or below the rate of inflation. The 2018 Financial Plan organizes the statutes and policies that guide financial decisions and establishes a set of financial health objectives that are foundational to the Strategic Plan.¹⁰ In the first rate period after these plans were released, Bonneville has extended this effort and established an objective for the Integrated Program Review (IPR) process for the FY 2020–2021 rate period to keep total costs flat in nominal terms relative to FY 2018–2019 spending—effectively resulting in Bonneville absorbing approximately \$80 million per year in inflation.¹¹

Meanwhile, in the first quarter of FY 2018, financial conditions were expected to worsen, with Bonneville's Power Services business line forecast to close out FY 2018 with negative \$42 million in financial reserves; this means Power Services would have had to borrow \$42 million to fund its daily operations.¹² Power Services experiences more relative financial

⁷ See BONNEVILLE POWER ADMIN., FOCUS 2028, <https://www.bpa.gov/Finance/FinancialPublicProcesses/2028/Pages/default.aspx> (last visited Jun. 19, 2018); Brian McConnell, *Bonneville Power Administration Cost Management*, BONNEVILLE POWER ADMIN. (Feb. 2016), https://www.bpa.gov/Finance/FinancialPublicProcesses/2028/doc2028/Focus%202028_BPA%20Cost%20Management.pdf; Bonneville Power Administration, *Wrap-Up* (Feb. 12, 2016), <https://www.bpa.gov/Finance/FinancialPublicProcesses/2028/doc2028/Wrap-Up%20Session.pdf>.

⁸ BONNEVILLE POWER ADMIN., Annual Report 2017 (2017), <https://www.bpa.gov/Finance/FinancialInformation/AnnualReports/Documents/AR2017.pdf>.

⁹ BONNEVILLE POWER ADMIN., U.S. DEP'T OF ENERGY, BPA 2018-2023 STRATEGIC PLAN (Jan. 2018), <https://www.bpa.gov/StrategicPlan/Pages/Strategic-Plan.aspx>.

¹⁰ See BONNEVILLE POWER ADMIN., U.S. DEP'T OF ENERGY, FINANCIAL PLAN 2018, at 3 (Feb. 2018), <https://www.bpa.gov/Finance/FinancialInformation/FinancialPlan/Pages/default.aspx>.

¹¹ See BONNEVILLE POWER ADMIN., U.S. DEP'T OF ENERGY, INTEGRATED PROGRAM REVIEW, Initial Publication, at 6, 14 (June 2018), <https://www.bpa.gov/Finance/FinancialInformation/FinancialPlan/Pages/default.aspx>. (The IPR process is a regional cost review and control process, occurring every two years. The IPR provides interested parties and stakeholders an opportunity to review, discuss, and comment on all proposed agency expense and capital spending level estimates, prior to each rate case.)

¹² BONNEVILLE POWER ADMIN., U.S. DEP'T OF ENERGY, QUARTERLY BUSINESS REVIEW, at 18 (Jan. 30, 2018), <https://www.bpa.gov/Finance/FinancialPublicProcesses/QuarterlyBusinessReview/2013QBRDocuments/Quarterly%20Business%20Review%20January%202018.pdf>; Bonneville Power Admin, Jan. 30 QBR Transcript, 10, <https://www.bpa.gov/Finance/FinancialPublicProcesses/QuarterlyBusinessReview/2013QBRDocuments/Jan.%2030%20QBR%20transcript.pdf>.

volatility than many other utilities due to streamflow and market uncertainty. Financial reserves are Bonneville's preferred and primary tool to buffer against this volatility.¹³ Similarly sized AA-rated utilities typically carry between \$750 million and \$1.25 billion in financial reserves to manage daily operations and buffer against financial volatility.¹⁴ At the time Power Services' financial reserves were forecast to be negative at the end of the fiscal year, the likelihood of needing to implement a mid-rate-period rate adjustment in the form of a Cost Recovery Adjustment Clause (CRAC) was 72 percent. It has been more than a decade since Bonneville had to use its CRAC to increase revenue within a rate period.

Third-party rating agencies have also expressed concerns about Bonneville's financial position, particularly with respect to low financial reserves and high leverage. Near the beginning of FY 2018, Fitch Ratings put bonds supported by Bonneville's financial obligations on a negative outlook, which could result in a credit rating downgrade if Bonneville's financial position does not improve.¹⁵ A credit rating downgrade could increase Bonneville's cost of capital, which would increase Bonneville's overall costs and lead to further upward pressure on Bonneville's rates. Bonneville's Strategic and Financial Plans establish goals for improving financial reserves and leverage, and meeting those goals would help alleviate some of the rating agencies' primary concerns.

In light of deteriorating financial conditions in the first quarter, Bonneville implemented aggressive near-term measures to manage costs across the agency in FY 2018 in order to avoid triggering or minimize a mid-rate-period rate increase (*i.e.*, CRAC and Spill Surcharge), and avoid further depletion of financial reserves. Cost-reduction measures were implemented across the board in FY 2018, affecting all organizational cost pools¹⁶ and nearly every aspect of Bonneville's business.¹⁷ These budget reductions across Bonneville's programs, including those forecast for Fish and Wildlife, would have occurred regardless of the existence of the Spill Surcharge.

As a result of these cost-management actions over the last several months, Bonneville has reduced its operating year budget by \$44 million and plans to reduce it by an additional

¹³ See BONNEVILLE POWER ADMIN., *supra* note 1, at 255. JP02 also supports Bonneville's position that financial reserves are Bonneville's primary and preferred source of liquidity. *Id.*

¹⁴ According to Moody's, entities similar to Bonneville hold between 150 and 250 days cash on hand. See BONNEVILLE POWER ADMIN., *supra* note 1, at 224.

¹⁵ *Fitch Rates Energy Northwest, WA's Electric Rev Bonds 'AA'; Outlook Negative* FITCH RATINGS (May 1, 2018, 3:17 PM); *Ratings Direct: Energy Northwest, Washington, Bonneville Power Administration, Oregon; Wholesale Electric*, STANDARD & POOR'S GLOBAL RATINGS (May 1, 2018). As part of the recent Energy Northwest bond transaction, third-party rating agencies have held credit ratings for bonds supported by Bonneville's financial obligations constant, while noting that sustaining this rating will require careful, persistent implementation of these plans to reverse current negative financial trends and improve Bonneville's overall financial health. See, e.g., Moody's Investor Service, RATING ACTION: MOODY'S ASSIGNS AA1 TO ENERGY NORTHWEST (WA) COLUMBIA GENERATING STATION AND PROJECT 3 REVENUE BONDS. OUTLOOK STABLE, MOODY'S (May 1, 2018).

¹⁶ For budgeting purposes, Bonneville's four organizational cost pools are Power, Transmission, Corporate, and Chief Administrative Office.

¹⁷ See BONNEVILLE POWER ADMIN., U.S. DEP'T OF ENERGY, QUARTERLY BUSINESS REVIEW, (May 1, 2018), <https://www.bpa.gov/Finance/FinancialPublicProcesses/QuarterlyBusinessReview/2013QBRDocuments/Quarterly%20Business%20Review%20May%202018.pdf>.

`\$20 million for a total of \$64 million this fiscal year. These reductions will significantly impact each of Bonneville's four organizational cost pools. A significant portion of these cost reductions will reduce the risk of triggering a CRAC in the current fiscal year, which, at the close of the second quarter, dropped to just 8 percent.¹⁸ Once there was sufficient information about planned spill operations for Spring 2018, however, Bonneville also had to decide which, if any, of these FY 2018 cost reductions would be attributed as an offset to the Spill Surcharge rather than retained to improve Bonneville's financial reserve levels. Bonneville proposed to attribute the forecast Fish and Wildlife program budget reductions to the Spill Surcharge formula, consistent with how Bonneville manages budgets by organizational cost pool. The Spill Surcharge was designed to address imperfect and asymmetrical information available at the time Bonneville's BP-18 rates were set regarding the forecast costs of planned annual fish passage spill.¹⁹ The costs of fish passage spill (a combination of forgone power sales revenue and increased power purchases) are classified as a Fish and Wildlife cost.²⁰ Allocating a forecast reduction in Fish and Wildlife Program spending to the Spill Surcharge formula in order to offset the costs of increased spill is consistent with this longstanding cost classification and part of the broader across-the-board cost-management efforts in FY 2018, in which the budget for each organizational cost pool has been significantly reduced relative to the start-of-year FY 2018 budget.

The agencywide cost management efforts under way and the decisions allocating the resulting cost savings among separate administrative processes are being implemented consistent with the Strategic and Financial Plans. These plans establish a framework of near-term, mid-term, and long-term measures to improve Bonneville's financial condition and foster resiliency. The framework will stand against shifting energy markets and other factors beyond the ability of Bonneville to predict or control.

This FY 2018 Spill Surcharge decision, which recovers costs of the surcharge through a combination of cost-management actions and an FY 2018 power rate increase for Bonneville's customers, demonstrates a balanced approach and a continued commitment to meeting the Strategic and Financial Plan goals of improving Bonneville's overall financial health in both cost management and financial resiliency. This effort will provide for long-term financial sustainability and allow Bonneville to continue providing competitive cost-based electric power and transmission services and fulfilling other valuable public service responsibilities for the region.

¹⁸ See *id.*, BONNEVILLE POWER ADMIN., U.S. DEP'T OF ENERGY, MAY 1 QBR TRANSCRIPT, 10 (2018), <https://www.bpa.gov/Finance/FinancialPublicProcesses/QuarterlyBusinessReview/2013QBRDocuments/May%20%20Quarterly%20Business%20Review%20transcript.pdf>.

¹⁹ See BONNEVILLE POWER ADMIN., *supra* note 1.

²⁰ See, e.g., NORTHWEST POWER AND CONSERVATION COUNCIL, 2016 COLUMBIA RIVER BASIN FISH AND WILDLIFE PROGRAM COSTS REPORT, <https://www.nwcouncil.org/reports/2016-columbia-river-basin-fish-and-wildlife-program-costs-report>.

3. The Spill Surcharge

3.1 Statutory Context

Section 7 of the Northwest Power Act governs the development of Bonneville's wholesale power and transmission rates. 16 U.S.C. § 839e. Section 7(a)(1) requires the Administrator to establish rates in order to recover Bonneville's costs:

The Administrator shall establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Such rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this chapter and other provisions of law. . . .

16 U.S.C. § 839e(a)(1).

Section 7(a)(2) of the Act provides that Bonneville's rates are confirmed and approved by the Federal Energy Regulatory Commission (FERC) only if they recover Bonneville's costs:

Rates established under this section shall become effective only, except in the case of interim rules as provided in subsection (i)(6), upon confirmation and approval by the Federal Energy Regulatory Commission upon a finding by the Commission, that such rates—

(A) are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs,

(B) are based upon the Administrator's total system costs, and

(C) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system.

16 U.S.C. § 839e(a)(2).

In addition to requiring Bonneville's rates to recover its costs, the Act grants the Administrator broad discretion in the design of Bonneville's rates. Section 7(e) of the Act provides:

Nothing in this chapter prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms.

16 U.S.C. § 839e(e). Pursuant to this discretion to design Bonneville's rates, Bonneville has a long-established practice, going back over 30 years, of establishing formula rates and adjustment clauses. *See, e.g.*, Residential Exchange Program and Supply System Adjustment Clauses, 1985 General Rate Schedule Provisions Sections III.C.6 and 7, approved by FERC on a final basis; *United States Department of Energy – Bonneville Power Administration, Order Confirming and Approving Rates On A Final Basis And Terminating Dockets*, Docket No. EF85-2011-011 (April 29, 1987). Like adjustment clauses, formula rates enable utilities to pass through to ratepayers increases or decreases in certain costs, which are not known before the rate period, without the need to file formal rate changes or conduct formal rate hearings.

3.2 Procedural Context: *National Wildlife Federation* Opinion and the BP-18 Power Rate Proposal

Bonneville published the BP-18 Initial Proposal in November 2016, which reflected revenues Bonneville expected to receive from selling energy in the FY 2018–2019 rate period, based in part on the spill assumptions informed by spill levels specified in the current Biological Opinion. In April 2017, the U.S. District Court for the District of Oregon issued a ruling in *National Wildlife Federation v. National Marine Fisheries Services* granting in part motions for an injunction with respect to spring fish passage spill levels for the 2018 juvenile fish passage season. In its opinion, the court stated that it would order “increased spill,” but directed the parties to the lawsuit to work together with experts in the region to develop specific spill levels in the form of a spill implementation plan and a proposed injunction order.²¹

Water that is “spilled” at a dam is not run through a generation turbine but instead is passed via a spillway or other non-turbine route (*e.g.*, an ice and trash sluiceway). The consequence of additional spill is a reduction in available generation. Reductions in generation result in reductions in revenue because Bonneville is unable to sell energy associated with the amount of water that is spilled. All else being equal, reduced revenues associated with an increase in planned annual spill levels would affect the ability of Bonneville's initially proposed BP-18 rates to recover its total costs. Bonneville Staff therefore concluded in the spring of 2017 that the *National Wildlife Federation* ruling would impact Federal hydroelectric system operations during the BP-18 rate period. Because the ruling was issued after the release of the BP-18 Initial Proposal, it created a new cost risk for Bonneville. This new cost risk was both substantial in size (possibly multiple millions of dollars) and asymmetrical in nature, meaning that it would result in a higher net cost because it would reduce the amount of Federal generation available for sale by Bonneville. As a result, Bonneville could not ignore the potential cost impact during the BP-18 rate period²² despite the fact that Bonneville did not know at that time how the court's ruling would impact spill operations in 2018 or 2019.

Bonneville Staff did not propose to model in rates any potential effects of the court's decision because the planned spill operations for 2018 were not yet known. As described above, spill assumptions for FY 2018 would be established in a court-ordered process, which would be conducted outside of the rate case and would be completed after rates were set. Bonneville Staff did not want to speculate on the outcome of this process, whether through revised hydro

²¹ *Nat'l Wildlife Fed. v. Nat'l Marine Fisheries Serv.*, No.3:01-cv-0640-SI, slip op., at 21-24 (D. Or. Apr. 3, 2017).

²² *See Golden NW Aluminum v. Bonneville Power Admin.*, 501 F.3d 1037, 1048-53 (9th Cir. 2007).

modeling or inclusion of a fixed-cost line item, and proposed instead to develop a targeted surcharge that would address the cost risk of increased planned spill when more information was known. The Spill Surcharge is formula-based and evaluates each fiscal year of the rate period independently, comparing increases in planned annual spill levels relative to the spill levels assumed in setting rates. Bonneville Staff proposed that the Spill Surcharge be added to Bonneville's Priority Firm (PF), Industrial Firm (IP), and New Resources Firm (NR) power rates to address this new cost risk and thereby ensure that Bonneville's rates would recover its total forecast costs.

Because Bonneville was proposing a new surcharge, rather than updating data and information, it incorporated the development of the Spill Surcharge into the BP-18 Section 7(i) rate hearing to ensure that parties had an opportunity to thoroughly review and provide input on the proposal. The BP-18 procedural schedule was revised to accommodate the parties' review.

On April 17, 2017, Bonneville held a conference with rate case parties to develop a procedural schedule for the establishment of the Spill Surcharge within the BP-18 rate hearing. After the scheduling conference, in which the litigants reached consensus on a proposed schedule, Bonneville filed a motion with the hearing officer to amend the BP-18 procedural schedule. On April 21, 2017, the hearing officer granted the motion and established the schedule. Pursuant to the "supplemental phase" of the schedule, Bonneville Staff filed its direct testimony on April 27, 2017. The testimony was subject to oral and written discovery by the parties. The parties filed their direct testimonies on May 11, 2017. The parties' testimonies were subject to oral and written discovery by the litigants. On May 25, 2017, Bonneville and another litigant filed respective rebuttal testimonies responding to the parties' direct testimonies. The testimonies were subject to oral and written discovery by the parties. The parties filed initial briefs on June 9, 2017. The Administrator adopted the Spill Surcharge in the BP-18 Final Record of Decision (ROD) on July 26, 2017.

3.3 Description of the Spill Surcharge

This section presents a summary description of the Spill Surcharge. The Spill Surcharge has two overarching components, one of which increases revenue while the other reduces expenses. The Spill Surcharge is designed to ensure that Bonneville is able to recover forecast costs if planned spill levels increase for FY 2018 and/or FY 2019 by increasing Bonneville's revenue collection from PF, IP, and NR energy sales when the planned annual spill levels increase relative to the spill levels assumed in setting rates; or on balance, reduce expenses to achieve the assumed level. Under the Spill Surcharge, Bonneville evaluates each fiscal year of the rate period independently.

3.3.1 Spill Surcharge Amount

The Spill Surcharge recovers the costs calculated by the Spill Surcharge Amount, which determines the additional cost to be charged to customers. The Spill Surcharge Amount formula has four main components:

1. the *Spill Cost Component*, which determines the cost (or lost revenue) associated with an increase in planned annual spill relative to the spill assumed when setting rates;

2. the *Cost Reductions Component (CostR)*, which allows the Administrator to decrease the Spill Surcharge Amount when Bonneville observes or forecasts reductions in program spending relative to the fiscal year program spending used for the purpose of setting rates;
3. the *Secondary Reduction Component (SecR)*, which reflects the net impact of increased spill on Bonneville's balancing purchases and remaining secondary sales. It accounts for the impact that more spill would have on the market-clearing price. On average, more spill would cause an upward shift in the forecast Mid-C market-clearing price, which would impact Bonneville's balancing purchases and remaining secondary sales; and
4. the *Non-Slice Component*, which adjusts the entire formula to reflect the operational and cost-recovery differences between Slice and Non-Slice PF power sales. Non-Slice power sales are subject to the surcharge, whereas Slice power sales are not because they are directly impacted by increased spill and are subject to an annual cost and revenue true-up.

Spill Cost Component

The Spill Cost Component determines the cost (or lost revenue) associated with an increase in planned annual spill relative to the spill assumed when setting rates; *i.e.*, Bonneville calculates the cost of lost generation caused by additional spill. Bonneville first determines the difference between the Federal regulated hydro generation from two studies: (1) the hydro regulation (HYDSIM) study used in the BP-18 Final Proposal (which does not reflect additional spill); and (2) a revised HYDSIM study that will use the BP-18 Final Proposal study with the new spill assumptions for the applicable year modeled. In addition, the lack-of-market spill data inputs in the revised HYDSIM studies will be updated. Similar to many other aspects of BP-18 ratesetting methodologies, the Federal generation data from both studies will be based on 80 historical water conditions modeled. A statistical forecast is produced by multiplying the resulting differences in generation between the two studies by the BP-18 Final Proposal market price forecast for each month over the 80 historical water conditions modeled. The resulting costs in each month for every year are summed and divided by 80 to determine the Spill Cost Component.

Cost Reductions Component

The Cost Reductions Component (*CostR*) variable used in the Spill Surcharge formula is a dollar amount of specific forecast and actual program spending reductions determined at the discretion of the Administrator. Generally, program spending is identified in Bonneville's IPR process and consists of forecasts of expenses that will appear on Bonneville's income statement, but does not include debt management, interest, power purchase costs, revenue credits, net secondary revenue, the Residential Exchange Program, or discounts.

Secondary Reduction Component

The Secondary Reduction Component (*SecR*) reflects the net impact of increased spill on Bonneville's balancing purchases and remaining secondary sales. It accounts for the impact that more spill would have on the market-clearing price and thus on the region as a whole. On average, more spill would cause an upward shift in the forecast Mid-C market-clearing price, increasing electricity prices for the entire region, which would impact Bonneville's balancing purchases and remaining secondary sales.

Non-Slice Component

Under current long-term power sales contracts, Bonneville’s preference customers purchase firm requirements power under one of three products: Load Following, Block, and Slice/Block. All customers are assessed monthly power bills determined by applicable PF rates. The Spill Surcharge applies to sales of power under the Load Following and Block (collectively, “non-Slice”) products. The Non-Slice Component of the Spill Surcharge adjusts the formula to reflect the operational and cost recovery differences between Slice and non-Slice PF power sales. Power sold under the Slice product is directly impacted by increased spill—the cost of spill (reduction in generation) is incorporated into the product, and the customer assumes the associated cost risk independent of Bonneville. As such, the Slice portion of a Slice/Block customer’s load is not subject to the Spill Surcharge. Therefore, the Non-Slice Component reduces the Spill Surcharge Amount proportionately to apply only to non-Slice power products.

3.3.2 Spill Surcharge Implementation

Calculation of Spill Surcharge Rate and Annual Spill Surcharge Rate

A Spill Surcharge Amount is calculated once each fiscal year in 2018 and 2019 when there is sufficient certainty around the revised spill assumptions and any offsetting cost reductions for that fiscal year. Bonneville calculates the Spill Surcharge and starts the public process (described below) no later than the last day of May in each fiscal year. The Spill Surcharge Amount cannot be negative. If Bonneville determines that the Spill Surcharge Amount for a fiscal year would be less than \$5 million, then the Spill Surcharge Amount is deemed to be zero. Once the Spill Surcharge is finalized for a fiscal year, it is not revisited.

The Spill Surcharge Rate is calculated by dividing the Spill Surcharge Amount by the forecast billing determinants under the PF Melded, IP, and NR rates, and the sum of the PF System Shaped Loads for the unbilled remaining portion of the applicable fiscal year. The Spill Surcharge Rate is also used to adjust the PF Tier 1 Equivalent rates for the unbilled remaining portion of the applicable fiscal year. Finally, Bonneville calculates an Annual Spill Surcharge Rate to adjust the Load Shaping Charge True-Up rate and the PF Melded Equivalent Energy Scalar rate.

Public Process

Bonneville conducts a public process prior to finalizing and implementing the Spill Surcharge. Bonneville makes available the data and assumptions used to calculate the Spill Surcharge Amount, Spill Surcharge Rate, and Annual Spill Surcharge Rate; holds a public meeting to describe the calculations; and provides a public comment period before the amount, rate, and adjustment are made final. The assumptions include the dollar amount of any forecast and actual cost reductions identified by the Administrator for use in calculating the Spill Surcharge Amount.

Billing

The Spill Surcharge Rate is used in billing as follows. The Spill Surcharge Rate increases the Heavy Load Hour (HLH) and Light Load Hour (LLH) energy rates under PF Melded, IP, and NR service for the remaining portion of the fiscal year. For PF customers with a System Shaped

Load, the Spill Surcharge Rate applies to the sum of the HLH and LLH PF System Shaped Loads in each month for the remaining portion of the fiscal year. A customer's Low Density Discount is applied to its share of the Spill Surcharge Amount.

To help avoid possible cash flow problems for Bonneville's customers, the Spill Surcharge includes a provision to allow a customer to request that its share of the FY 2018 Spill Surcharge be spread in a flat monthly amount over the remaining months of FY 2018 plus all 12 months of FY 2019. Bonneville will accommodate such requests if there are no material adverse impacts on its cash flow.

Other Adjustment Clauses

Bonneville's adjustment clauses for power rates—the Power CRAC, the Power Reserves Distribution Clause (RDC), and the NFB (Biological Opinion) mechanisms—work in the context of the Spill Surcharge as follows. The Power CRAC and the RDC applying to FY 2018 rates are not affected by the Spill Surcharge. The Power CRAC and the RDC that apply to FY 2019 will account for any additional revenue resulting from the Spill Surcharge. In addition, the Spill Surcharge does not change the determination of an NFB trigger event; however, revenues received from the Spill Surcharge are included for the purpose of calculating the NFB Adjustment and the Emergency NFB Surcharge. This means that if an NFB event occurs during the rate period, Spill Surcharge revenue is taken into account as part of the “before case” and is not charged for again under the NFB mechanisms.

4. FY 2018 Spill Surcharge

Bonneville calculated the Spill Surcharge Amount for FY 2018 in accordance with the formula specified in the Spill Surcharge. The resulting Spill Surcharge Amount is \$10.2 million. A summary table showing each component is provided in Attachment 1. Documentation is provided on Bonneville's website.²³ The calculation of the Spill Surcharge Amount and rates described below was made available to customers and interested parties for their review and comment. *See* Section 4.3, Review of Public Comments. Attachment 2 shows additions to the 2018 Power Rate Schedules and GRSPs to reflect results from implementation of the Spill Surcharge for FY 2018.

4.1 FY 2018 Spill Surcharge Calculation

Spill Cost Component

In order to determine the cost associated with an increase in planned annual spill, the 2018 Final Rate Proposal hydro study was rerun using new spill criteria (spill assumptions) shown in the documentation. (The original spill criteria can be found on page 111 of the Power Loads and Resources Study Documentation, BP-18-FS-BPA-03A.) These spill criteria were updated to reflect the spill plan incorporated into the district court's injunction order dated January 8, 2018. Hydro study outputs reflecting the new spill criteria were run through the AURORAxmp[®] model to update lack-of-market spill, which was subsequently incorporated into the hydro study.

²³ Available at <https://www.bpa.gov/Finance/RateCases/surcharge18/Pages/default.aspx>.

The new spill criteria resulted in a 253 aMW decrease in 80-year average hydro generation and a FY 2018 cost (*i.e.*, decreased revenue) of \$38.6 million using the template as established through the ratesetting process.

Secondary Reduction (SecR)

Based on an electricity price forecast using the AURORAxmp[®] model, the prices at Mid-C increase during the spring spill months due to lost Federal generation. Forecast price increases relative to prices in the BP-18 final rate proposal are: \$1.32/MWh for April; \$1.54/MWh for May; and \$0.88/MWh for June. These numbers reflect a forecast of the higher energy prices the entire region pays as a result of changes in planned spill operations at the eight Federal dams equipped with fish passage facilities. In total, the price effect contributes to an additional \$7.6 million in modeled *SecR*, after adjusting for the amount of Spill Surcharge that will not be collected due to Low Density Discounts.

Cost Reductions (CostR)

As described above, Bonneville has been working on reducing its program budgets across the agency as part of a larger exercise delivering on Strategic Goal 1 in the Bonneville 2018–2023 Strategic Plan—to strengthen financial health. Consistent with Bonneville’s Strategic Plan and its BP-18 Spill Surcharge formula, Bonneville is applying its forecast Fish and Wildlife program cost reductions of \$20 million for FY 2018 to the Spill Surcharge and is allocating other agencywide forecast FY 2018 cost reductions to strengthen Bonneville’s financial health. All forecast cost reductions are relative to the costs modeled in Bonneville’s final BP-18 rates.

While Bonneville is forecasting it will spend \$20 million less than its rate case estimates on Fish and Wildlife in FY 2018, actual cost reductions will occur in the normal course of Fish and Wildlife program management. To calculate *CostR*, \$20 million in forecast cost reductions for Fish and Wildlife spending is reduced by 22.3 percent to account for the reduction of the credit that Bonneville takes from the U.S. Treasury for non-power-related fish mitigation efforts. The credit is authorized pursuant to NWPA section 4(h)(10)(C) so that Bonneville pays only for the power share of fish mitigation programs and not for the share of those costs allocated to the other purposes of the FCRPS, such as navigation and flood control.²⁴ 16 U.S.C. § 839b(h)(10)(C). Bonneville’s cost savings of \$20 million translates to \$15.5 million in actual savings after adjusting for the reduced credit.

Spill Surcharge Amount and Rates

The Spill Surcharge Amount of \$10.2 million results in a Spill Surcharge rate of 0.71 mills per kilowatthour for June–September 2018 and an Annual Spill Surcharge rate of 0.23 mills per kilowatthour. See Attachment 1. The Spill Surcharge rate is equal to the Spill Surcharge Amount divided by the sum of billing determinants for the unbilled remaining portion of the Fiscal Year. The rate is used to bill PF customers and IP customers and to adjust the June–September 2018 PF Tier 1 equivalent energy rates.

²⁴ See *supra* note 3.

The Annual Spill Surcharge rate of 0.23 mills per kilowatthour is equal to the Spill Surcharge Amount divided by the sum of billing determinants for FY 2018. The Annual rate is used to adjust the Load Shaping Charge True-Up rate and the PF Melded Equivalent Energy Scalar rate (which is used in the actual DSI revenue credit calculation in the Slice True-Up).

Extended Billing

Pursuant to the Spill Surcharge, section D, a customer may request a payment schedule of flat monthly amounts that recover its FY 2018 Spill Surcharge over the remaining months of the FY 2018–2019 rate period, up to 16 months. In consideration of such a request, Bonneville must review its own cash flow and the potential impact a delayed cost recovery could have on other customers and on triggering a CRAC. No customer has made such a request.

4.2 Notification of Preliminary FY 2018 Spill Surcharge

The Spill Surcharge, section F, Notification, provides that Bonneville will hold at least one public meeting to review the calculation of the preliminary Spill Surcharge Amount, Spill Surcharge Rate, and the Annual Spill Surcharge Rate no later than May 31 of each Fiscal Year. This meeting occurred on May 16, 2018, in Bonneville’s Rates Hearing Room. In advance of the meeting, on May 8, Bonneville provided documentation of the calculations described in section 4.1, above, as well as explanatory information. The Spill Surcharge, section F, also provides that Bonneville will provide at least 10 business days for comment on the preliminary data and assumptions. Bonneville provided the interested parties from May 16 through June 7 to offer comments on the proposed implementation of the Spill Surcharge for FY 2018. Finally, the Spill Surcharge, section F, directs Bonneville to issue the final Spill Surcharge Amounts and rates no later than 14 calendar days after the comment period closes, and to apply such rates in the next available billing cycle.

4.3 Review of Public Comments

Bonneville received eight comments from interested parties, although one of the comments from a private citizen expressed concern about pollution in our environment, and did not address the Spill Surcharge. Comments were filed regarding the design of the Spill Surcharge (which is an issue regarding the establishment of the Spill Surcharge in the BP-18 rate proceeding), and the need for Bonneville to control its costs. Because the design of the Spill Surcharge is a BP-18 ratemaking issue and not an implementation issue, none of the comments expressed any objection to the manner in which Bonneville was proposing to implement the Spill Surcharge.

A number of comments expressed appreciation for Bonneville’s efforts in managing this issue. The Public Power Council (PPC) appreciates the work of Bonneville Staff in managing the impacts of a high-cost, court-ordered operation under difficult circumstances. (PPC at 1.) The Alliance of Western Energy Consumers (AWEC) appreciates Bonneville’s efforts to reduce the impact to customers through internal cost reductions, resulting in a lower Spill Surcharge Amount. (AWEC at 1.) The Western Public Agencies Group (WPAG) lauds and commends Bonneville, and its Staff, for making a broad cost management commitment to aggressively secure its competitiveness by decreasing costs directly within Bonneville’s control, for finding new avenues to better control and manage Bonneville’s indirect costs, for uncovering new methods that diversify Bonneville’s sources of revenue and effectively reduce Bonneville’s

reliance on the short-term market, and for beginning the process of cutting costs to meet this commitment. (WPAG at 1.) Bonneville appreciates the parties' support as it faces significant challenges to remain a competitive source of wholesale power.

The following discussion notes the comments made by the parties and Bonneville's responses to the comments.

4.3.1 Design of the BP-18 Spill Surcharge

The NW Energy Coalition (NVEC) addresses the design of the Spill Surcharge, suggesting that the current design could expose customers to higher costs than necessary. (NVEC at 1.) NVEC states it would be better if the Spill Surcharge were calculated based on actual hydro operations and actual market prices. (*Id.* at 1-2.) NVEC also suggests that the Spill Surcharge should allow more leeway for recovery of the surcharge through the remainder of the rate period, not simply the few months between imposition of the surcharge and the end of the fiscal year. (*Id.* at 2.) NVEC notes that if the court-ordered spill to the gas caps continues beyond the current BP-18 rate period, a separate surcharge may not be needed, and the effect of additional spill could be included in the regular billing determinants. (*Id.*)

Bluefish.org (Bluefish) states that Bonneville Staff did not respond adequately to an interested party questioning Bonneville's use of forecast values (instead of actual values) at the May 16, 2018, workshop. (Bluefish at 1-2.) Bluefish states that it presents a clear way to estimate the Spill Surcharge using actual values and that its approach provides an alternative to Staff's proposal for the Administrator to decide upon. (*Id.* at 2.) Bluefish believes that use of actual values could result in avoiding the need for a Spill Surcharge this year. (*Id.*) Bluefish then presents what it believes could be a method of calculating a Spill Surcharge using actual numbers. (*Id.* at 2-9.)

In response to these comments, Bonneville notes that the current Spill Surcharge proceeding addresses only the *implementation* of the Spill Surcharge based on the formula that was established in Bonneville's BP-18 rate case. Bonneville's BP-18 rates, including the Spill Surcharge, were confirmed and approved on a final basis by FERC. *See* Order Confirming and Approving [Bonneville] Rates on a Final Basis, 162 FERC ¶ 61,248 (Mar. 19, 2018). In the BP-18 Final ROD, which concluded the proper forum for resolving Spill Surcharge rate design issues, Bonneville reviewed the Staff proposal and alternative proposals from rate case parties at great length, including proposals to use actual numbers, and issued a reasoned decision after its review. The current implementation proceeding cannot consider or make any changes to the existing Spill Surcharge formula, including changes to the recovery period for the surcharge, because any such changes can be made only in a ratemaking hearing conducted pursuant to section 7(i) of the NWPAs. 16 U.S.C. § 839e(i). Nevertheless, all comments regarding the design of the Spill Surcharge have been provided to Bonneville Staff for its consideration in developing Bonneville's BP-20 initial rate proposal. If Bonneville proposes a Spill Surcharge in the BP-20 initial proposal, parties are encouraged to raise their alternative rate design proposals in the BP-20 rate proceeding.

4.3.2 Cost Management

PPC notes that increased spill is the product of a legal process outside of Bonneville's control. (PPC at 1.) PPC notes that without the costs of additional spill, Bonneville could have otherwise applied the significant cost savings achieved towards reducing the chances of a future rate adjustment and toward working for a more cost-competitive future. (*Id.*) PPC supports finding cost reductions and efficiencies in the Integrated Fish and Wildlife Program and suggests that as operations for fish reduce power production, Bonneville should manage the integrated program by reducing direct expenditures commensurate with operational costs. (*Id.*) PPC believes tradeoffs between operations and direct program expenses are reasonable and illustrate that the consumers paying Bonneville's costs have a finite capacity for mitigation. (*Id.*)

The Northwest Requirements Utilities (NRU) state that minimizing or eliminating additional rate increases is key to maintaining an affordable retail and wholesale power supply. (NRU at 1.) NRU believes the agency needs to consider the cumulative impact of all rate increases, including the Tier 1 rate increase, the Spill Surcharge, a possible CRAC, and possible additional surcharges under discussion across the agency. (*Id.*) While these rate impacts may be levied on a piecemeal basis, NRU notes that they aggregate into a significant rate impact to end-users. (*Id.*)

AWEC states that the imposition of the Spill Surcharge imposes a significant burden on AWEC members, who are major employers and contributors to local economies throughout the region. (AWEC at 1.) AWEC believes the surcharge may tend to have a negative effect on the regional economy. (*Id.*) Nonetheless, AWEC appreciates Bonneville's efforts to reduce impact to customers through internal cost reductions and is pleased with the resulting lower Spill Surcharge Amount. (*Id.*) AWEC remains concerned about the overall level of Bonneville's fish and wildlife costs. (*Id.*) Although the Spill Surcharge was judicially imposed, AWEC appreciates Bonneville's willingness to review its Fish and Wildlife programs in light of increasing costs associated with this required spill, and AWEC looks forward to Bonneville's upcoming Integrated Program Review for further discussion of these issues. (*Id.*)

WPAG states that whereas costs savings identified by Bonneville as part of the IPR process benefit its customers and the region's consumers in the form of lower rates, the cost savings Bonneville finds during the rate period primarily benefit Bonneville and do not reduce the BP-18 rates paid by Bonneville's customers or their consumers.²⁵ (WPAG at 1.) WPAG states that Bonneville's power customers are already being called upon to make substantial payments to support Bonneville's financial health, including paying surcharges or PNRR under Bonneville's financial reserve policy and supporting another round of Regional Cooperation Debt refinancing to help secure Bonneville's access to capital. (*Id.* at 2.) Bonneville is also considering some amount of revenue financing for capital projects for both the Power and Transmission business lines to preserve additional access to capital, and is considering a

²⁵ Bonneville disagrees with this statement. Bonneville is a not-for-profit Federal power marketing administration, and all costs and benefits ultimately flow to Bonneville's customers. Slice customers will see a benefit of Bonneville's cost reductions during the BP-18 rate period through the Slice True-Up. Non-Slice customers benefit from reduced exposure to the BP-18 CRAC. To the extent these cost reductions are not needed to prevent or lower a BP-18 CRAC, Bonneville's cost reductions would increase financial reserves that provide other longer-term benefits, such as rate stability, to customers.

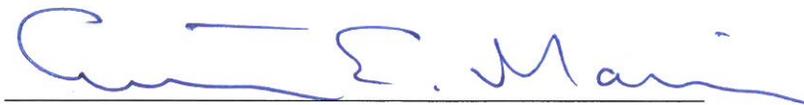
proposed leverage policy that would impose an additional cost of supporting Bonneville's financial health on power customers in their capacities as Bonneville transmission customers. (*Id.*) All of these actions to improve Bonneville's financial health will come, in whole or in part, at the expense of Bonneville's power customers. (*Id.*) In return, Bonneville should commit to use all diligent efforts to give its customers the benefit of any and all costs savings by including such savings in its IPR budgets and thereby reduce Bonneville's rates. (*Id.*) WPAG looks forward to Bonneville's 2018 IPR process and learning more about Bonneville's recent cost-management activities. (*Id.*)

In response to the foregoing comments, Bonneville acknowledges the challenges it faces in remaining a competitive power supplier for the future. In its May 16, 2018, presentation on the Spill Surcharge, Bonneville Staff described recent efforts to reduce program budgets across the agency as part of a larger exercise in delivering on the Strategic Plan goal of strengthening Bonneville's financial health. Consistent with this strategic goal and the BP-18 Spill Surcharge formula, Bonneville proposed to apply its forecast Fish and Wildlife program cost reductions (\$20 million) to the Spill Surcharge and use forecast cost reductions from all other programs to strengthen Bonneville's financial health. Although the determination of the *CostR* component of the Spill Surcharge formula and the attribution of Fish and Wildlife program cost reductions to the *CostR* component are proper subjects for the implementation of the Spill Surcharge, broader cost reduction efforts are outside the scope of this process. As noted in a number of comments, Bonneville will be evaluating its program costs during its IPR process, which began on June 18, 2018, to inform the BP-20 rate case. Bonneville looks forward to engaging its customers and other interested parties in that forum.

5. Decision

Based upon the foregoing, I hereby implement the Spill Surcharge by adopting the final FY 2018 Spill Surcharge Amount of \$10.2 million, the final FY 2018 Spill Surcharge rate of 0.71 mills per kilowatthour for June–September 2018, and the final FY 2018 Annual Spill Surcharge rate of 0.23 mills per kilowatthour.

Issued at Portland, Oregon, this 21st day of June, 2018.



Elliot E. Mainzer
Administrator and Chief Executive Officer

Attachments

Attachment 1

Final FY 2018 Spill Surcharge Amount and Rates

A. Final FY 2018 Spill Surcharge Amount

Formula Component	Amount	Description
Spill Cost	\$38.6 million	The average lost generation due to more planned spill, over the modeled 80-historical-water-year record, multiplied by the rate case forecast Mid-C electricity price.
Cost Reductions (<i>CostR</i>)	<u>(\$15.5 million)</u>	Program spending reductions relative to those assumed for setting BP-18 rates. Represents a forecast reduction of \$20 million of F&W costs and the corresponding reduction in the NW Power Act section 4(h)(10)(C) credit (22.3% credit on F&W costs).
	\$23.1 million	
Non-Slice	<u>× .7726</u>	Adjusts formula to reflect costs associated with non-Slice PF power sales only.
	\$17.8 million	
Secondary Reduction (<i>SecR</i>)	<u>(\$7.6 million)</u>	Accounts primarily for the impact that more spill would have on the market-clearing price for the remaining secondary sales.
FY 2018 Spill Surcharge Amount	\$10.2 million	

B. Final FY 2018 Spill Surcharge Rate

0.71 mills per kilowatthour for June–September 2018

C. Final FY 2018 Annual Spill Surcharge Rate

0.23 mills per kilowatthour

Attachment 2

Additions to the 2018 Power Rate Schedules and General Rate Schedule Provisions

The following additions are being made to rate schedules and GRSPs for clarification. The new GRSP Appendix D (section III, below) is created to show rate and GRSP changes resulting from mid-rate period adjustments. Other additions to the rate schedules and GRSPs, Sections I and II, respectively, are shown in red.

I. Rate Schedule Additions

Priority Firm Power Rate, PF-18

2.1.5 Spill Surcharge

The Spill Surcharge, specified in GRSP Appendix C, is applicable to customers that purchase the Load Following product, the Block product, or the Slice/Block product for the Block portion of the service.

See GRSP Appendix D, Supplemental Information, for applicable FY 2018 and FY 2019 Spill Surcharges.

New Resource Firm Power Rate, NR-18

2.1.1.2 Spill Surcharge

The NR energy rates in Section 2.1.1 are subject to adjustment during the Rate Period pursuant to the Spill Surcharge, specified in GRSP Appendix C.

See GRSP Appendix D, Supplemental Information, for applicable FY 2018 and FY 2019 Spill Surcharges.

Industrial Firm Power Rate, IP-18

2.1.1.3 Spill Surcharge

The IP energy rates in Section 2.1.1 are subject to adjustment during the Rate Period pursuant to the Spill Surcharge, specified in GRSP Appendix C.

See GRSP Appendix D, Supplemental Information, for applicable FY 2018 and FY 2019 Spill Surcharges.

II. GRSP Additions

GRSP II.E. Load Shaping Charge True-Up Adjustment

The Load Shaping Charge True-Up Adjustment is applicable to customers purchasing the Load Following product in specific circumstances. The Adjustment shall be determined following each fiscal year of the rate period and shall appear on the customers' power bills.

1. Load Shaping Charge True-Up Rate

<i>FY</i>	<i>Rate in mills/kWh</i>
2018	-12.75
2019	-12.75

The Load Shaping Charge True-Up rates are subject to adjustment during the Rate Period by the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); the Emergency NFB Surcharge (GRSP II.Q); and the Spill Surcharge (GRSP Appendix C).

See GRSP Appendix D, Supplemental Information, for adjusted Load Shaping Charge True-Up rates.

GRSP II.R. Slice True-Up Adjustment

(c) Calculation of the Actual DSI Revenue Credit

(3) DSI Take-or-Pay revenues

Where:

Actual kWh amount of DSI sales and DSI Take-or-Pay revenues shall be obtained from BPA data sources.

-22.24 mills/kWh is calculated by the equation:

PFMEES - 9.58 mills/kWh

Where:

PFMEES is the PF Melded Equivalent Energy Scalar of -12.66 mills/kWh and is subject to the Power CRAC, the Power RDC, the NFB Emergency Surcharge, and the Spill Surcharge.

See GRSP Appendix D, Supplemental Information, for adjusted PF Melded Equivalent Energy Scalars.

GRSP Appendix C: Spill Surcharge

F. Notification

For each year of the rate period, BPA will notify customers of the preliminary Spill Surcharge Amount to be recovered by the Spill Surcharge for the fiscal year (if any). Such notice will be provided as soon as practicable, but in no case later than May 31 of each Fiscal Year. BPA will make available to customers the preliminary data and assumptions relied upon to calculate the surcharge including any proposed program spending reductions.

BPA will hold at least one public meeting to review the calculation of the Spill Surcharge Amount, Spill Surcharge Rate, and the Annual Spill Surcharge Rate. BPA will provide at least 10 business days for comment on the preliminary data and assumptions. No later than 14 calendar days after the comment period closes, BPA will issue the final Spill Surcharge Amount, Spill Surcharge Rate, and the Annual Spill Surcharge Rate, and apply such rates in the next available billing cycle. **See GRSP Appendix D, Supplemental Information, for applicable FY 2018 and FY 2019 Spill Surcharges.**

III. New Appendix

Appendix D

Supplemental Information

Adjustments to rates and GRSPs during the Rate Period due to the Power CRAC (GRSP II.O), the Power RDC (GRSP II.P), the Emergency NFB Surcharge (GRSP II.Q), and the Spill Surcharge (GRSP Appendix C) are summarized here.

I. Spill Surcharge for Fiscal Year 2018

Spill Surcharge Rate **0.71 mills/kWh for the months of June–September, 2018**
Annual Spill Surcharge Rate **0.23 mills/kWh**

A. Spill Surcharge for Rate Schedules

Rate Schedule/Service	For June – September 2018 service, the Spill Surcharge Rate of 0.71 mills/kWh shall be applied to the following billing determinants:
PF (Section 2.1.5) <ul style="list-style-type: none">• Load Following• Block• Block portion of Slice/Block	System Shaped Load for HLH and LLH
PF Melded Rate (Section 3)	Total hourly energy loads for each diurnal period
NR (Section 2.1.1.2)	Total of NR Hourly Loads for each diurnal period
IP (Section 2.1.1.3)	Energy Entitlement

B. GRSP Factors Adjusted by Annual Spill Surcharge Rate (0.23 mills/kWh)

GRSP	Adjusted factors for FY 2018
GRSP II.E, Load Shaping Charge True-Up Adjustment, Section 1	Load Shaping True-Up Rate = -12.98 mills/kWh
GRSP II.R, Slice True-Up Adjustment, Section 1(c)	PF Melded Equivalent Energy Scalar (PFMEES) Rate = -12.89 mills/kWh

C. GRSP II.AA. Priority Firm Power (PF) Tier 1 Equivalent Energy Rates for FY 2018 Adjusted by Spill Surcharge Rate^{1/}

<i>FY 2018</i>	<i>Energy Rate in mills/kWh</i>	
	<i>HLH</i>	<i>LLH</i>
June	31.17	22.77
July	38.12	32.51
August	41.57	36.07
September	41.40	35.65

^{1/}Spill Surcharge Rate of 0.71 mills/kWh is added to June–September 2018 energy rates (shown in chart). All other PF Tier 1 Equivalent rates (energy and demand) remain the same.

