Oregon
Kate Brown, Governor

Public Utility Commission
201 High St SE Suite 100
Salem, OR 97301-3398
Mailing Address: PO Box 1088
Salem, OR 97308-1088
503-373-7394

November 15, 2022

BY EMAIL
PacifiCorp
oregondockets@pacificorp.com

RE: Advice No. 22-011

At the public meeting on November 15, 2022, the Commission adopted Staff's recommendation in this matter docketed as ADV 1436. The Staff Report and a receipted copy of the sheets in your advice filing are attached.

Nolan Moser

Nolan Moser
Chief Administrative Law Judge
Public Utility Commission of Oregon
(503) 378-3098

ITEM NO. CA2

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: November 15, 2022

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** ____**November 16, 2022**____

DATE: November 7, 2022

TO: Public Utility Commission

FROM: Nick Sayen

THROUGH: Bryan Conway, JP Batmale, and Sarah Hall **SIGNED**

SUBJECT: PACIFIC POWER:
(Docket No. ADV 1436/Advice No. 22-011)
Introduces a commercial and industrial demand response program through Schedule 106, proposes cost recovery through Schedule 291, and cancels Schedule 218.

STAFF RECOMMENDATION:

Approve Pacific Power's (Company or PacifiCorp) Advice No. 22-011.

DISCUSSION:

Issue

Whether the Oregon Public Utility Commission (Commission) should authorize introduction of a commercial and industrial demand response program through Schedule 106; recovery of those program costs through Schedule 291; and cancellation of Schedule 218.

Applicable Rule or Law

PacifiCorp makes this filing pursuant to ORS 757.205, OAR 860-022-0025, and OAR 860-022-0030.

- ORS 757.205 requires public utilities file to all rates, rules, and charges with the Commission.

- ORS 757.220 requires utilities to file changes to any rates, tolls, charges, rules, or regulations with at least 30 days before the effective date of the changes. The Commission may approve tariff changes on less than 30 days' notice for good cause shown.
- OAR 860-022-0025 requires that revised tariff filings include statements showing the change in rates, the number of customers affected and resulting change in annual revenue, and the reasons for the tariff revision.

OAR 860-022-0030 requires that tariff filings which result in increased rate include statements showing the number of customers affected, the annual revenue under existing schedules, the annual revenue under proposed schedules, the average monthly bills under existing and proposed schedules, and the reasons supporting the proposed tariff.

Analysis

Background

This memo provides background, summary of the Company's proposed changes, and review of impacts to other programs and stakeholder involvement. The memo concludes with Staff's recommendation to approve the Company's filing.

In Pacific Power's 2019 Integrated Resource Plan (IRP), Staff and stakeholders recommended the Company pursue increased demand response (DR) capacity through a request for proposals (RFP). In acknowledging the 2019 IRP, the Commission adopted this suggestion attaching conditions to Action Item No. 4 which require, in part, that:

> PacifiCorp pursue demand response acquisition with a demand response RFP.
>
> PacifiCorp should work with non-bidding stakeholders from Oregon and other interested states to determine whether PacifiCorp should move forward with cost-effective demand response bids, or with a demand response pilot, or both.[1]

As Pacific Power notes in this filing, the proposed program is part of the continuing implementation of those conditions. The RFP was issued in early 2021 and emphasized that bidders include programs in the Company's Oregon or Washington service areas,

[1] See Order No. 20-186, page 22, https://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=20-186.

and products that achieve at least three megawatts (MW) in three years, scalable to 25 MW over five to ten years.

The Company received bids from numerous firms that covered multiple programs and sectors. Bids were scored comprehensively and considered by program category. Each category represented a discrete set of customer end uses, such as irrigation or residential water heating. The top bid for each program category was selected for inclusion in 2021 IRP modeling. In the 2021 IRP, modeling costs were characterized via RFP bids and the IRP Conservation Potential Assessment (CPA) and compared against supply side resources. The modeling identified a need for DR not just in the short term but throughout the planning horizon (2021–2040). The 2021 IRP preferred portfolio included the addition of 33 MW of cost-effective DR covering multiple customer types and programs in Oregon for 2022, with additional MWs being brought on in subsequent years.

As a result of this modeling the Company requested and received approval for a broad DR tariff, Schedule 106, to support multiple programs.[2] Schedule 106 outlines basic enabling elements applicable to the multiple programs. Each DR program entails specific details separate from the basic enabling elements defined in Schedule 106. Rather than include program specific details in the tariff itself, Schedule 106 allows for those details to be published and maintained on the Pacific Power website within a section for each program. If the Company seeks to make changes to Schedule 106, add or remove a pilot or a program, or make substantial changes to pilot or program budgets, it must engage in the typical regulatory tariff revision process. However, if the Company seeks to make changes to the program specific details it is not required to engage in the typical regulatory tariff revision process. Instead, the Company will engage in a stakeholder notification and comment gathering process.[3]

Staff summarizes the distinction between changes that would and would not involve the typical regulatory tariff revision process, and Commission notification and approval, in the table on the next page.

[2] See Docket No. ADV 1383, https://edocs.puc.state.or.us/efdocs/UBF/adv1383ubf10320.pdf.
[3] See Docket No. ADV 1383, Pacific Power Advice No. 22-004, filed March 28, 2022, Exhibit E, https://edocs.puc.state.or.us/efdocs/UAA/uaa153323.pdf.

Table 1 – Summary of Changes and Requirements

Changes that <u>would require</u> Commission notification/approval/regulatory tariff revision process:	**Changes that <u>would not require</u> Commission notification/approval/ regulatory tariff revision process:**
1. Changes to Schedule 106 2. Add pilots/programs covered by Schedule 106 3. Remove pilots/programs covered by Schedule 106 4. Propose a change of expenditures greater than 30% of total estimated annual budgets for programs covered by Schedule 106	1. Eligibility requirements: customer class or technical criteria 2. Dispatch periods, days, and hours 3. Dispatch events and duration 4. Event dispatch notification 5. Customer incentive levels 6. Event opt-out parameters

PacifiCorp has already utilized Schedule 106 to establish a program for irrigation customers.[4] The program proposed in this filing is the second DR program to utilize the provisions of Schedule 106.

Summary of Proposed Changes

1. *<u>New Demand Response Program for Commercial and Industrial Customers</u>*

Pacific Power proposes to introduce a DR program for commercial and industrial customers (C&I Program). The C&I Program would be covered by Schedule 106 and does not have an end date, which aligns with ongoing capacity needs in the 2021 IRP period. The C&I Program will include four participation options (also labeled product categories). These are structured around the minimum amount of notification time participants will have between when the Company calls and begins an event. These participation options provide varying grid services. Participation options and associated grid services are:

- 60-minute-ahead: load curtailment
- 20-minute-ahead: regulation reserve
- Seven-minute-ahead: contingency reserve
- Real time (no notice): frequency response

The first evaluation of the C&I Program will be completed after 2023, the first full year of program operation, with subsequent evaluations to occur no less frequently than every two years. Staff notes select features of the C&I Program below. Additional details of

[4] See Docket No. ADV 1383, https://edocs.puc.state.or.us/efdocs/UBF/adv1383ubf10320.pdf.

the program which vary by participation option, including incentives, can be found in Exhibit B of this filing:

- **Eligibility:** All commercial and industrial customers on Delivery Service Schedules 23, 28, 30, 47, and 48
- **Dispatch period:**
  - 60-minute-ahead: May 1 – September 30
  - 20-minute-ahead, seven-minute-ahead, and real time: January 1 – December 31
- **Dispatch days:**
  - 60-minute-ahead and 20-minute-ahead: Weekdays, non-Holidays during Dispatch Period
  - Seven-minute-ahead, and real time: Monday through Sunday during Dispatch Period
- **Available dispatch hours**
  - 60-minute-ahead: 3:00 p.m. to 9:00 p.m. Pacific Time on all Dispatch Days
  - 20-minute-ahead: 8:00 a.m. to 9:00 p.m. Pacific Time on all Dispatch Days
  - Seven-minute-ahead and real time: 24 hours/day on all Dispatch Days
- **Maximum dispatch hours**
  - 60-minute-ahead: 40 hours per year
  - 20-minute-ahead, and Seven-minute-ahead: 60 hours per year
  - Real time: five hours per year

Pacific Power estimates the expanded program will achieve demand capacity of approximately 43 MW from 80 participant sites in 2022-2023, reaching over 53 MW from 100 participant sites in 2024-2026. This amount comfortably exceeds the 32 MW of capacity from Oregon commercial and industrial customers selected by the 2021 IRP.

The C&I Program will be delivered by Enel X. The firm was the successful bidder in the 2021 Demand Response RFP and is also delivering DR services for the same customer group in PacifiCorp's Rocky Mountain Power service territory. Enel X is responsible for the installation, operation, and maintenance of the load control devices; dispatch of the devices as directed by the Company; customer participation; customer service; and issuance of customer incentives. The Company, Enel X, and the Energy Trust of Oregon team will collaborate, so customers have cohesive messaging around energy efficiency and DR opportunities at their facilities.

Estimated costs for the C&I Program are included in this filing and include vendor costs, customer incentives, customer outreach/advertising, evaluation, measurement, and verification, and utility staffing costs directly attributable to managing the program. These costs include the impacts of customers participating in the participation options as follows:

- 60-minute-ahead: 33 percent of total impacts
- 20-minute-ahead: 33 percent of total impacts
- Seven-minute-ahead: 17 percent of total impacts
- Real time (no notice): 17 percent of total impacts

Estimated costs are presented in the Staff-generated table below. The filing notes that at this point in the year, 2022 costs should be considered as incurred in either 2022 or 2023, and thus be additive to the 2023 costs.

Table 2 – Estimated C&I Program Costs

	2022	**2023**	**2024**	**2025**	**2026**
Total Program Costs	$3,293,417	$3,906,166	$3,891,633	$3,891,633	$3,875,663

The Company must prospectively provide cost-effectiveness from a Total Resource Cost (TRC) and Utility Cost Test (UCT) perspective when seeking Commission approval for a new DR program and retrospectively as part of the annual reporting.[5] The Company proposes to continue using the 2016 California Demand Response Protocol to calculate cost effectiveness. This filing notes that use of this protocol was most recently discussed at the December 6, 2021, Demand Response Workshop. This protocol was also recommended in Staff's 2016 memo approving the Company's original irrigation demand response pilot.[6] Staff supports continuation of this approach until the Commission establishes a different cost effectiveness approach.

The C&I Program's prospective cost effectiveness calculations are provided in this filing as Confidential Exhibit A. Calculations are provided for each of the four notification options, in four separate spreadsheet workbooks. Staff reviewed each of the four workbooks, and the calculations appear reasonable and accurate.

Prospective cost effectiveness results for the C&I Program are included in this filing. Each of the four participation options are cost effective from the UCT and TRC perspectives when ten years of benefits and costs are compared.[7] The results are presented in the Staff-generated table on the next page.

[5] See Docket No. ADV 1383, https://edocs.puc.state.or.us/efdocs/UBF/adv1383ubf10320.pdf.
[6] See Docket No. ADV 242, Staff Report, page 5, https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAU&FileName=adv242hau16236.pdf.
[7] As discussed previously, the real-time participation option provides frequency response services. The filing notes that frequency events are unpredictable and difficult to model on a prospective basis, and so a deferred utility resource is used to approximate the value of solving issues related to frequency events using a utility supply side resource.

Table 3 – Prospective C&I Program Cost Effectiveness Scores

Program Participation Option	UCT	TRC
60 minute-ahead	1.3	1.6
20 minute-ahead	1.5	1.8
Seven minute-ahead	1.2	1.5
Real time (no notice)	1.0	1.2

The filing notes that the 20-minute and seven-minute participation cost effective scores are sensitive to the utility need for, and utility value of, reserve grid services in 2025 and beyond. The filing also notes that the forecast from the 2021 IRP for increased utility-scale battery installations diminishes the reserve values in outer years. In discussing this filing with the Company, Staff requested analysis to explore the sensitivity of C&I Programs cost effectiveness to diminishing reserve values in future years. Specifically, Staff requested analysis to understand the impact should utility-scale battery installations not be able to provide competing reserve grid services (due to either increased costs or delayed implementation).

In response, the Company re-ran the cost effectiveness calculations using longer-persisting reserve values: the average reserve values across the first five years were assumed through the final five years of the study period. As a result, the 20-minute UCT increased from 1.5 to 1.6, and the seven-minute UCT increased from 1.2 to 1.4. The 20-minute TRC increased from 1.8 to 2.0, and the seven-minute TRC increased from 1.5 to 1.8.

Staff also requested analysis to understand the impact should utility-scale battery installations be able to provide even more competitive reserve grid service (due to decreased costs or accelerated implementation). In response, the Company referenced updated information on utility-scale battery prices provided as part of 2023 IRP process. Indications are the prices will be appreciably higher than those included in the 2021 IRP, and therefore, cost effective results for these participation options are relatively conservative. The Company did not conduct any analyses around lower battery prices in light of this information.

In sum, if utility-scale battery installations experience either increased costs or delayed implementation, the C&I Program will become even more cost effective. Alternatively, decreasing costs of utility-scale battery installations do not pose a significant risk to the C&I Program cost effectiveness. Staff appreciates the time the Company spent on these additional analyses in response to these requests.

Staff supports Pacific Power's proposed C&I Program as it builds on the Company's experience delivering a similar offering in the Rocky Mountain Power service territory, and cost-effectively meets needs forecast by the IRP.

2. *Recovery of those Program Costs through Schedule 291*

Pacific Power proposes to recover C&I Program costs through Schedule 291. This is consistent with Pacific Power's Advice No. 21-022, approved by the Commission, December 28, 2021.[8] It is also consistent with the approach taken with the irrigation DR program. The Company is not proposing a change to Schedule 291 as part of this filing. Instead, once the C&I Program is approved, the Company will file an application to defer the costs incurred through the program for later recovery through Schedule 291. Staff supports this approach.

3. *Cancellation of Schedule 218*

This filing notes that Schedule 218, the Interruptible Service Pilot, was approved in the Company's 2021 general rate case, and allows large customers to provide flexible loads in exchanged for reduced bills. The Pilot features aggregate limits on participating loads, minimum requirements for the interruptible load, and administrative fees to offset associated costs. While the Pilot launched January 1, 2021,[9] a preliminary report filed on June 15, 2022, showed no customers were participating.[10]

Pacific Power proposes to cancel the Pilot for several reasons, firstly the lack of participation. In addition, the Company states the proposed C&I Program is superior as it is available to a broader range of customers and offers multiple participation options with varying incentives. Based on this reasoning, Staff supports the cancellation of the Schedule 218.

---

[8] See Docket No. ADV 1344, Pacific Power Advice No. 21-022, filed November 15, 2021. The advice filing created a new Schedule 291 to consolidate the recovery of costs to fund energy efficiency, transportation electrification, and demand response programs. The filing was in response to the passage of HB 3141, which removed energy efficiency funding from the Public Purpose Charge, and HB 2165, which specified new funding for transportation electrification. The filing also canceled Schedule 95, the tariff through which Pacific Power previously recovered costs of its original irrigation load control pilot. https://edocs.puc.state.or.us/efdocs/UAA/uaa16439.pdf.

[9] See Docket No. UE 374, Pacific Power Advice No. 20-017, filed December 28, 2020, https://edocs.puc.state.or.us/efdocs/UHR/ue374uhr1061.pdf.

[10] In paragraph 15 of the partial stipulation adopted in PacifiCorp's last general rate case, Docket No. UE 374, Order No. 20-473, the Company committed to providing parties an initial report on its Schedule 218 Pilot by June 15, 2022. As of that date there were no customers on Schedule 218, and so no initial report to deliver. Instead, a letter documenting this circumstance was delivered to parties of the partial stipulation. While this filing stated the preliminary report was filed with the Commission, the partial stipulation only required the report be served on parties, which the Company did appropriately.

Impacts to Other Programs

1. *Coordination with other Schedule 106 Programs*

The C&I Program will be coordinated with other Schedule 106 offerings. This includes:

- Reporting – the Company has proposed to provide an annual report by March 31 each year for the irrigation DR program and the C&I Program.
- Program review – Company has proposed the same approach for annual programmatic review of the irrigation DR program and the C&I Program.

Staff appreciates this approach and believes it will provide administrative efficiency to the Company, stakeholders, and Staff. Staff encourages the Company to pursue all sensible opportunities to coordinate the administration of Schedule 106 Programs.

2. *Schedule 73, Large Customer Curtailment Option*

In discussing this filing with the Company Staff inquired about customers' ability to enroll in the C&I Program, and enroll in Schedule 73. The Company explained that the purpose of the Schedule 73 program was to reduce the need for, or duration of, any required rotating outages by allowing qualifying customers to voluntarily reduce their load. Qualifying customers would not receive any participation payment from the Company. However, they would receive electric service during any rotating outages. Pacific Power communicated that available records do not indicate any qualifying customers participated, and no qualifying customers are currently on Schedule 73.

The Company has communicated to Staff that it intends to cancel Schedule 73. The cancellation will be initiated through a subsequent and separate advice filing, later in November 2022. The Company communicated several reasons for this, namely the lack of customer participation. In addition, cancelling Schedule 73 would eliminate the need to manage co-participation in programs with the same intended outcomes. Finally, the C&I Program is superior as it is available to a broader range of customers and offers multiple participation options with varying incentives. Based on this reasoning, Staff communicated support for cancelling Schedule 73 in a future advice filing.

Stakeholder Feedback/Involvement

This filing documents stakeholder involvement in developing the C&I Program. This stakeholder involvement grew out of the demand response RFP and IRP related activities. This included approximately 20 different opportunities including CPA workshops, DR workshops, regular IRP public input meetings, meeting with Energy Trust of Oregon staff, utilizing a consultant to research DR vendors, conducting the

RFP, and updating Commission Staff. Stakeholder involvement specific to the C&I Program included meeting with a large commercial customer to assess DR opportunities at the site, as well as conducting a test event at the site. Pacific Power provided a draft of the C&I Program filing to the parties from prior DR workshops and requested comments on the draft. The Energy Trust of Oregon was the only stakeholder to provide comments on the Company's draft filing. The Company also met several times with Energy Trust of Oregon staff.

Conclusion

Staff supports Pacific Power's proposed C&I Program as it builds on the Company's experience delivering a similar offering in the Rocky Mountain Power service territory and cost-effectively meets needs forecast by the IRP. Staff supports the Company's approach to recovering costs associated with the Program. Finally, Staff supports the cancellation of Schedule 218.

PROPOSED COMMISSION MOTION:

Approve Pacific Power's (Company or PacifiCorp) Advice No. 22-011.

Received
Filing Center
OCT 14 2022

+Schedule No.

	SUPPLY SERVICE	
200	Base Supply Service	
201	Net Power Costs – Cost-Based Supply Service	
210	Portfolio Time-of-Use Supply Service	
211	Portfolio Renewable Usage Supply Service	
212	Portfolio Fixed Renewable Energy– Supply Service	
213	Portfolio Habitat Supply Service	
220	Standard Offer Supply Service	D
230	Emergency Supply Service	
247	Partial Requirements Supply Service	
276R	Large General Service/Partial Requirements Service – Economic Replacement Power Rider Supply Service	
	ADJUSTMENTS	
90	Summary of Effective Rate Adjustments	
91	Low Income Bill Payment Assistance Fund	
92	Low Income Discount Cost Recovery Adjustment	
93	Independent Evaluator Cost Adjustment	
94	Wildfire Mitigation and Vegetation Management Cost Recovery Adjustment	
96	Property Sales Balancing Account Adjustment	
97	Intervenor Funding Adjustment Cost Recovery Adjustment	
98	Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act	
101	Municipal Exaction Adjustment	
103	Multnomah County Business Income Tax Recovery	
104	Oregon Corporate Activity Tax Recovery Adjustment	
194	Replaced Meter Deferred Amounts Adjustment	
195	Federal Tax Act Adjustment	
198	Deer Creek Mine Closure Deferred Amounts Adjustment	
202	Renewable Adjustment Clause – Supply Service Adjustment	
203	Renewable Resource Deferral – Supply Service Adjustment	
204	Oregon Solar Incentive Program Deferral – Supply Service Adjustment	
205	TAM Adjustment for Other Revenues	
206	Power Cost Adjustment Mechanism – Adjustment	
207	Community Solar Start-Up Cost Recovery Adjustment	
270	Renewable Energy Rider – Optional	
271	Energy Profiler Online – Optional	
272	Renewable Energy Rider – Optional Bulk Purchase Option	
290	Public Purpose Charge	
291	System Benefits Charge	
294	Transition Adjustment	
295	Transition Adjustment – Three-Year Cost of Service Opt-Out	
296	Transition Adjustment – Five-Year Cost of Service Opt-Out	
299	Rate Mitigation Adjustment	

Received
Filing Center
OCT 14 2022

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Nonresidential Consumers receiving Delivery Service under Schedule 48, in conjunction with Supply Service Schedule 201. Participation will be limited to the first twenty-five (25) megawatts of load on a first come, first served basis.

Monthly Billing

The Monthly Billing shall be the Interruptible Demand Credit, Interruptible Energy Credit, and Administrative Fee. The Monthly Billing is in addition to all other charges contained in Delivery Service Schedule 48, Base Supply Service Schedule 200 and Supply Service Schedule 201.

Interruptible Demand Credit	
Per kW of On-Peak Interruptible Demand	-$1.00
Interruptible Energy Credit	
Per kWh of Interrupted Energy	-20.000¢
Administrative Fee	
Per month	$90.00

Interruption Events

The Company may call up to 100 hours of Interruption Events each calendar year. One Interruption Event may be called each day and may not exceed 3 consecutive hours. Each Interruption Event called by the Company shall be set for a period of at least 15 minutes in duration. Interruption Events may be called on any day or at any time during the year. During Interruption Events, a participant's usage shall not exceed their Baseline Non-Interruptible Load.

Interruption Notification

At least 30 minutes prior to an Interruption Event, the Company shall notify participants.

Interrupted Energy

Interruptible Energy during each Interruption Event shall be measured as the difference between the average load in kW for the 2 hours preceding the Interruption Event and the Baseline Non-Interruptible Load multiplied by the duration of the Interruption Load in hours.

Interruptible Demand

Interruptible Demand shall be measured as the kW shown by or computed from the readings of the Company's demand meter for the highest 15-minute period during On-Peak as defined by Delivery Service Schedule 48 during the month, determined to the nearest kW, less the Baseline Non-Interruptible Load.

Baseline Non-Interruptible Load

Once per calendar year, participants may nominate a Baseline Non-Interruptible Load in kW which shall not be subject to Interruption Events.

(continued)

Received
Filing Center
OCT 14 2022

Interruptible Service Term

Unless otherwise removed from this schedule by the Company, participants shall agree to remain on Interruptible Service for a period of no less than 12 months. After terminating service under this schedule, a Consumer may not re-enroll for a 12 month period.

Special Conditions

1. If a participant does not interrupt its load by reducing its usage down to its Baseline Non-Interruptible Load or less during an Interruption Event, the participant shall be subject to the following penalties:
   a. For the first failure in a rolling 12 month period, the participant shall forfeit its Interruptible Demand Credit and Interruptible Energy Credit for the month in which it failed to interrupt.
   b. For the second failure in a rolling 12 month period, the participant shall forfeit its Interruptible Demand Credit and Interruptible Energy Credit for the month in which it failed to interrupt and for the prior six months.
   c. For the third failure in a rolling 12 month period, the participant shall be removed service on this schedule.
2. Participants removed from the schedule may not return to Interruptible Service for a period of 12 months.
3. Participants on this schedule may not also take service on Schedule 219 – Real-Time Day Ahead Pricing Pilot.
4. As a condition of receiving service on this schedule, the Company may elect to upgrade and/or update the Consumer's metering to record five minute interval data and otherwise be capable of being a participating resource in the Energy Imbalance Market. Any metering upgrade and/or update shall be at the Consumer's expense. The Company shall provide an estimate of the metering upgrade and/or update to the Consumer prior to incurring any expense.
5. Participants must nominate a Baseline Non-Interruptible Load that results in at least 1,000 kW of Interruptible Load.
6. At its sole discretion, the Company may elect to not provide service under this schedule or remove from participation Consumers with seasonal loads that do not correspond to the times of the year when anticipated Interruption Events may occur.
7. A Consumer may not enroll in this schedule for more than 10 MW of service.
8. A Consumer may not at the same time participate in this schedule and Schedule 219 or any other demand response program.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.