

Exhibit No. ___ T (JBT-1T)
Dockets UE-140762, et al.
Witness: Jeremy B. Twitchell

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFIC POWER & LIGHT
COMPANY,

Respondent.

UE-140762 and UE-140617
(consolidated)

In the Matter of the Petition of

PACIFIC POWER & LIGHT
COMPANY,

For an Order Approving Deferral of
Costs Related to Colstrip Outage.

DOCKET UE-131384 (consolidated)

In the Matter of the Petition of

PACIFIC POWER & LIGHT
COMPANY,

For an Order Approving Deferral of
Costs Related to Declining Hydro
Generation.

DOCKET UE-140094 (consolidated)

TESTIMONY OF

Jeremy B. Twitchell

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Title

October 10, 2014

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1 I. INTRODUCTION

2
3 Q. Please state your name and business address.

4 A. My name is Jeremy Twitchell and my business address is 1300 Evergreen Park Drive
5 SW, Olympia, Washington, 98504.
6

7 Q. Where are you employed and in what capacity?

8 A. I am employed at the Washington Utilities and Transportation Commission
9 (Commission) as a Regulatory Analyst in the Conservation and Energy Planning
10 Section of the Regulatory Services Division. My duties include representing
11 Commission Staff (Staff) in Pacific Power & Light Company's (Pacific Power or
12 Company) demand-side management and integrated resource planning advisory
13 groups and reviewing all filings from the Company in those matters. I also represent
14 Staff in Pacific Power's Multi-State Allocation Process. More broadly, I review the
15 annual renewable portfolio standard filings from Washington's three investor-owned
16 electric utilities, various tariff filings in the electric and natural gas industries, and
17 assist in the drafting of Commission rules.
18

19 Q. How long have you been employed by the Commission?

20 A. I have been employed by the Commission since June 2013.
21

1 **Q. Please describe your educational and professional background.**

2 A. I graduated from Brigham Young University in 2005 with a Bachelor of Arts degree
3 in Communications (Print Journalism Emphasis), then worked as a newspaper
4 reporter in Utah and Nevada for six years covering local government, energy, and
5 other issues. I graduated from Texas A&M University with a Master of Public
6 Service and Administration degree in 2013, with an emphasis on energy, natural
7 resource, and technology policy. My studies included courses in energy markets,
8 energy policy, natural resource economics, finance, and econometric analysis. Since
9 being hired by the Commission, I have attended various conferences and regulatory
10 training courses, including a course in cost of service and rate design provided by
11 Electric Utility Consultants, Inc. in February 2014 and the National Association of
12 Regulatory Utility Commissioners Regulatory Studies Program in August 2014. I
13 also presented and participated in a panel on the issue of renewable portfolio
14 standard compliance costs at the 2014 National Summit on Renewable Portfolio
15 Standards in September 2014.

16

17 **II. SCOPE AND SUMMARY OF TESTIMONY**

18

19 **Q. What is the purpose of your testimony?**

20 A. I present Staff's recommendations on the Company's following proposals in this
21 proceeding:

- 22 • The Renewable Resource Tracking Mechanism (Gregory N. Duvall).
23 • The cost-of-service study and rate design (Joelle R. Steward).

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Q. Please summarize your recommendations regarding the Renewable Resource Tracking Mechanism.

A. The Commission should reject the Company’s proposed Renewable Resource Tracking Mechanism (RRTM or Mechanism) because it does not comply with the general standards for a power cost adjustment mechanism (PCAM) that the Commission has set forth in previous orders.

Q. Please summarize your recommendations regarding the cost-of-service study.

A. The Company’s cost-of-service study is a generally fair representation of the costs imposed on Pacific Power’s system by various customer classes. I have adjusted the study to reflect Staff’s proposed revenue requirement and to incorporate two of the three Staff recommendations that Pacific Power agreed to evaluate in the partial settlement reached in the 2013 rate case.¹ These recommendations – classifying wind-related generation costs as primarily energy related and directly assigning the costs of corporate account managers to the large industrial customers that they serve – are in line with cost causation principles. The Company examined those recommendations as agreed, but declined to implement them in its cost-of-service study.

¹ *WUTC v. Pacific Power & Light Company*, Docket UE-130043, Partial Settlement Regarding Cost of Service, Rate Spread, and Rate Design ¶ 12.

1 **Q. Please summarize Staff's recommendations regarding rate design.**

2 A. Staff recommends a rate design that more closely reflects cost causation by
3 allocating its proposed increase more heavily toward classes that are paying near or
4 below their verified cost of service and allocating no increase to classes that are
5 already paying well above their cost of service (105 percent or more). Staff's
6 proposal is also designed to create price signals that will encourage residential
7 customers to be more efficient in their energy usage. This approach, combined with
8 Staff's lower proposed revenue requirement, results in a different rate design than
9 that proposed by the Company.

10 On residential rate design, Staff's proposal would decrease the monthly bill
11 of the average residential customer using 1,300 kWh by 3.04, or 2.7 percent. This
12 proposal reflects a shift to collect more of the Company's fixed costs in the monthly
13 basic charge. Staff proposes to increase that charge from \$7.75 to \$13.00. Staff also
14 recommends that the Commission implement a three-tier, inverted-block rate
15 structure for residential customers. For most customers, the increase in the basic
16 charge will be offset by corollary reductions in the volumetric rates. Staff proposes
17 to increase the size of the first block to 0-800 kWh per month, establish a second
18 block of 801-1,700 kWh per month, and create a third block for all usage above
19 1,700 kWh per month.

20 The combination of these two changes – an increase in the basic charge and
21 the creation of a third tier – will reduce volatility in the Company's revenue recovery
22 and limit the overall bill increase for most residential customers. This proposal
23 would also shift a larger share of the rate increase to the highest users, in contrast

1 with the Company's proposal, which would actually decrease rates for the highest
2 residential users.² Implementing this shift would align the Company's rate design
3 with policies adopted by the State of Washington and the Commission to promote
4 investment in energy efficiency and renewable energy. It would also be more
5 reflective of cost causation, as higher users impose more burden, and therefore
6 greater costs, on the Company's system.

7 I have also prepared an alternate recommendation for residential rates, based
8 on the Company's proposal to implement a reduced basic charge for low-income
9 customers. This alternate recommendation suggests where the Commission should
10 place the basic charges for the different groups of residential customers if it chooses
11 to adopt the Company's proposal and provides analysis of what the impacts of that
12 policy would be on the monthly bills of all residential customers.

13 In general, Staff has not significantly altered the Company's proposed
14 approach to non-residential rates, other than differences arising from Staff's lower
15 revenue requirement and allocation of the overall increase. Where Staff proposes an
16 increase for a non-residential class, most of those increases have been evenly
17 allocated across usage-based charges (demand and energy charges), though Staff
18 does propose an increase in the basic charge for the Dedicated Facilities class.

19 20 **III. RENEWABLE RESOURCE TRACKING MECHANISM**

21
22 **Q. Please summarize Pacific Power's RRTM proposal.**

² Exhibit No. ___ (JRS-9).

1 A. Pacific Power proposes a mechanism that would track the Company's projected
2 value of its wind generation as calculated by the Company's model versus the actual
3 value of its wind generation in a given year. The Company would recover any
4 negative difference from ratepayers and refund any positive difference to ratepayers,
5 with both transactions taking place on a dollar-for-dollar basis. The difference
6 between projected and actual values would be tracked on a monthly basis in a
7 deferral account, and the Company would make an annual filing in July to true up
8 the account.

9

10 **Q. Is the RRTM a PCAM?**

11 A. Yes. Although it is narrow in scope, the RRTM is functionally a mini-PCAM. In his
12 testimony proposing the RRTM, Company witness Duvall states that the Mechanism
13 would:

14 Allow the Company to collect or credit the differences between the value of
15 resources included in Washington rates and eligible to comply with
16 Washington's renewable portfolio standard (RPS) established in the EIA, and
17 the actual value of these resources used to serve Washington customers.³
18

19 In testimony submitted in the 2013 General Rate Case, Mr. Duvall proposed a
20 PCAM that would "allow the Company to collect or credit the differences between
21 the actual (net power costs) incurred to serve Washington customers and the amount
22 of (net power costs) collected from Washington customers through rates."⁴

23 While narrower in scope, the RRTM would operate by the same mechanism
24 proposed for the PCAM in 2013. Both proposals would true up projected costs to

³ Direct Testimony of Gregory N. Duvall, Exhibit No. ____ (GND-1CT), at 38: 6-10.

⁴ *WUTC v. Pacific Power & Light Company*, Docket UE-130043, Exhibit No. ____ (GND-1CT), at 26: 4-7.

1 actual costs and recover any negative differential from ratepayers. If a positive
2 differential exists, then this amount would be returned to ratepayers. The RRTM's
3 reduced scope does not mean that it is not a PCAM; rather, the reduced scope makes
4 it an improperly designed PCAM.

5
6 **Q. How should a proper PCAM be designed?**

7 A. A properly designed PCAM should protect a Company from unexpected and
8 significant increases in power costs over a defined period. The Commission's
9 approval of cost recovery mechanisms such as the PCAM was never premised on
10 protecting a utility from all fluctuations in energy costs. Rather, these mechanisms
11 were intended to protect the utility and ratepayers from short-term and significant
12 increases in energy market prices – not normal market variation around the baseline.

13
14 **Q. Why is staff recommending that the Commission reject the proposed RRTM?**

15 A. First, the Company's proposed Mechanism does not contain dead bands or sharing
16 bands, which the Commission has identified as necessary components of a PCAM.
17 Second, the majority of the variation that the Company is claiming to justify the
18 RRTM is nothing more than normal market and weather variation, which the
19 Commission does not include in PCAMs. Finally, it is too narrow in scope, focusing
20 on one small component of the Company's net power costs (NPC).

21
22 **Q. Why are dead bands and sharing bands necessary components of an adjustment**
23 **mechanism?**

1 A. Dead bands create a strong price signal for a utility to effectively manage its NPC
2 and keep power costs low. The dead bands approved by the Commission create
3 upper and lower windows around the utility's approved NPC. If a company's actual
4 NPC fall within the lower dead band, then the utility and its shareholders may keep
5 the difference between actual NPC and the money the utility collects. If actual NPC
6 falls within the upper dead band, the utility and its shareholders must bear the
7 additional costs.⁵ The dead bands proposed by Staff in the Company's 2005 rate
8 case would have provided this incentive.⁶

9 Sharing bands allocate costs associated with unexpected market events
10 between shareholders and ratepayers. In the operation of a PCAM, once a
11 company's NPC exceeds the dead band, the additional and incremental costs or
12 benefits are distributed between shareholders and ratepayers according to established
13 guidelines. When they are combined, dead bands and sharing bands properly
14 motivate a utility to effectively manage its NPC and mitigate the impact of
15 unexpected and significant market events by spreading their costs across the utility
16 and its customers.

17 The cost recovery mechanisms approved for Puget Sound Energy (PSE) and
18 Avista Utilities (Avista) are good examples of proper PCAM designs that match the

⁵ For a summary of the Commission's position on the role of dead bands in a PCAM, see *WUTC vs. PacifiCorp d/b/a Pacific Power & Light Company*, Docket UE-050684, Order 04 (April 17, 2006), especially ¶ 93-96. For a summary of the structure of dead bands in Avista Corporation's PCAM, see *WUTC vs. Avista Corporation d/b/a Avista Utilities*, Docket UE-060181, Order 03.

⁶ *WUTC vs. Pacific Power & Light Company*, Docket UE-050684, Testimony of Alan P. Buckley, pg. 194 at 9-20.

1 general principles that I describe above. For both utilities, the Commission has
2 included dead bands and sharing bands in the mechanism's design.⁷

3
4 **Q. Has Pacific Power sought approval for a PCAM or PCAM-like mechanism in**
5 **prior rate cases?**

6 A. Yes. The Commission denied the Company's request for a PCAM in the 2005
7 General Rate Case because it did not include a dead band, noting:

8 (W)e observe that power cost recovery mechanisms should also apportion
9 risk equitably between ratepayers and shareholders. ... Deadbands and
10 sharing bands are useful mechanisms, not only to allocate risk, but to
11 motivate management to effectively manage or even reduce power costs.⁸

12
13 The Commission also rejected the Company's PCAM proposal in the 2013 General
14 Rate Case for its lack of dead bands and sharing bands, calling them

15 critically important elements that provide an incentive for the Company to
16 manage carefully its power costs and that protect ratepayers in the event of
17 extraordinary power cost excursions that are beyond the Company's ability to
18 control.⁹

19
20 The Commission's record on energy cost adjustment mechanisms is clear. To be
21 approved, a proposed mechanism must, at a minimum, include dead bands and
22 sharing bands. The RRTM has neither.

23
24 **Q. Why do you believe that the Company has not demonstrated enough variability**
25 **in its wind costs to justify the RRTM?**

⁷ *WUTC vs. Avista Corporation d/b/a Avista Utilities*, Docket UE-011595, Order 05 (June 18, 2002) ¶ 36;
WUTC v. Puget Sound Energy, Docket UE-011570, Order 12 (June 20, 2002) ¶ 22-24.

⁸ *WUTC v. Pacific Power*, Docket UE-050684, Order 04 (April 17, 2006) ¶ 96.

⁹ *WUTC v. Pacific Power & Light Company*, Docket UE-130043, Order 05 ¶ 170.

1 A. The Company's representation that it has under-recovered its power costs associated
2 with wind is largely based on normal market variability, which is the type of normal
3 variability that the Commission has previously told the Company is not recoverable
4 in a PCAM:

5 PacifiCorp, however, proposes a PCAM that would protect the Company
6 from any risk of under-recovery, even that due to the ordinary variability in
7 power costs due to normal and foreseeable changes in fuel costs, ordinary
8 variance in hydro conditions, normal variations in weather, and so forth. As
9 the Commission previously observed in connection with such a proposal:
10 'This would mark a new and much expanded role for the PCA.'¹⁰
11

12 Company witness Duvall maintains that wind variability in the WCA cost the
13 Company \$151.5 million (\$34.8 million on a Washington-allocated basis) from
14 2007-2012.¹¹ However, Exhibit No. ___(JBT-2) shows that \$110.7 million (73.1
15 percent) of that total is the result of the Company's over-forecasting of market
16 prices. For example, in 2009, the Company exceeded its projected wind production
17 by about 13,000 MWh. Despite that higher-than-expected generation, had the
18 RRTM been in place, the Company would have recovered \$17.5 million from WCA
19 ratepayers (\$4 million from Washington ratepayers) because the Company over-
20 estimated market prices. Specifically, the Company projected an average market
21 price of \$49.69/MWh. In fact, the average market price for the period was only
22 \$25.89/MWh.

23 That was just one example of the Company's widely missed forecasts of
24 market prices. As Exhibit No. ___(GND-1CT) shows, Pacific Power's cumulative
25 wind production forecasts over the period were within about 10 percent of actual

¹⁰ *WUTC v. Pacific Power & Light Company*, Docket UE-130043, Order 05, ¶ 172.

¹¹ Direct testimony of Gregory N. Duvall, Exhibit No. ___(GND-1CT), Table 7, Page 42.

1 values, but the Company's market price projections were, on average, about 96
2 percent higher than actual market prices. Given the Company's poor history of
3 forecasting market prices even in a period that lacked any large market shocks, the
4 RRTM would appear to expose ratepayers to significant, artificial risk.

5 Staff recognizes that when market prices are lower than projected, the
6 Company has fewer opportunities to sell electricity into the market and therefore
7 earns less offsetting revenue, which increases NPC. Conversely, however, if prices
8 are too low for a utility to sell into the market, then the utility may purchase power
9 that is cheaper than what it would produce itself, which reduces NPC. The RRTM,
10 as presented, makes the illogical argument that Washington ratepayers should
11 automatically bear higher costs when market prices fall.

12 The "value of wind" that the Company has developed to justify the RRTM is
13 a theoretical construct that does not represent any actual costs that the Company
14 incurs. Rather, Staff views it as an attempt to monetize normal market fluctuations,
15 which the Commission has clearly stated are not subject to recovery through an
16 adjustment mechanism.

17
18 **Q. Please explain why the RRTM is too narrow in scope.**

19 **A.** A properly designed PCAM should include all drivers of a company's NPC – not
20 just one. In other words, a company's NPC should include costs for all generation
21 resources serving Washington customers – not just a few.

22

1 Pacific Power deploys a diversified fleet of generation resources to serve
2 Washington customers. In addition to the Company's wind resources (which would
3 be segregated by its proposed RRTM), the Company's fleet includes hydropower
4 and thermal resources fueled by natural gas and coal. The Company's NPC reflects
5 the expected variability in use, and therefore cost, for all of these resources.

6 For example, the expected variability of Pacific Power's generation fleet is
7 affected by the cost of fuel necessary to operate its thermal resources. Another
8 influence on actual NPC is the availability of hydropower and wind energy to meet
9 load. If the Company's available generation resources are not sufficient to meet
10 load, then it will purchase power in regional energy markets – at prices determined
11 by the market at the time of purchase. Further, these energy markets are also used by
12 the Company to reduce dependence on its own resources during periods of
13 unexpected maintenance or when market prices are lower than its cost to run its own
14 generators.

15 The above are just examples of the potential variability the Company could
16 experience in a given period. The Company's power cost model takes all of these
17 influences into consideration, but it is just a model. The actual experience of the
18 Company will determine its actual NPC for the period.

19 The uncertainty associated with the Company's actual NPC is why the
20 RRTM should be rejected. Because it only seeks compensation for the variability in
21 available wind generation, it ignores the real possibility that the costs of its other
22 generators may be lower than that expected over the period in question. This is the
23 whole point of resource diversity. At any time, certain generators may be out of

1 service, out of the market or without water or wind. The Company's resource
2 diversity should usually be sufficient to make up any differences arising from
3 variations, and the Company can go to the market in unusual circumstances for
4 which its resource diversity cannot compensate. A properly designed PCAM
5 considers the net direction of all this movement, not just the movement of a single
6 resource type.

7 By segregating wind resources for special cost treatment, the Company
8 ignores the real chance that reduced costs in other areas of its generator portfolio
9 could more than offset any difference between the wind energy costs determined by
10 its NPC model and in-period actuals. Under the current regulatory model, Pacific
11 Power is allowed the opportunity to manage its resources to extract efficiencies that
12 reduce its overall NPC. If its overall NPC are lower than modeled, it is allowed to
13 keep the difference. Further, power costs tend to fluctuate up and down from year to
14 year. If the Company believes it is not allowed to recover higher-than-modeled
15 power costs over time, then it needs to review its decision to reject a PCAM
16 consistent with those approved by the Commission. A PCAM would most
17 effectively deal with its overall NPC. Singling out wind resources for special
18 treatment via the RRTM ignores the real issue – the Company's overall NPC.

19 The result that I advocate here is consistent with prior Commission orders, as
20 set forth earlier in my testimony. Similar mechanisms approved for Washington's
21 other investor-owned utilities have incorporated all of the factors affecting those
22 companies' NPC, with a few minor exceptions.¹²

¹² See *WUTC v. Avista Corporation*, Docket UE-011595, Order 05 (June 18, 2002) ¶ 35; *WUTC v. Puget Sound Energy*, Docket UE-011570, Order 12 (June 20, 2002) ¶ 23. For a summary of the limited NPC factors

1 In conclusion, the RRTM is an adjustment mechanism designed to address a
2 single factor of the utility's NPC. As such, the RRTM does not comply with
3 Commission precedent and is unlikely to resolve the issue it is meant to address. For
4 these reasons, Staff recommends that the Commission reject the RRTM. However,
5 Staff does address the variability in Pacific's total generation portfolio by proposing
6 a comprehensive PCAM. Staff witness David Gomez explains staff's proposal in
7 Exhibit No. ___ (DCG-1T) at pages 19-25.

8
9 **IV. COST OF SERVICE**

10
11 **Q. You previously mentioned that Pacific Power's cost-of-service study addressed**
12 **three recommendations made by Staff in the previous general rate case. What**
13 **was Staff's first recommendation?**

14 A. Staff recommended that the Company replace the system diversified load factor
15 (SDLF) methodology that it developed to classify costs as demand-related or energy-
16 related with a methodology that would classify costs by the top 100 winter hours and
17 top 100 summer hours of system demand (200 CP method).

18
19 **Q. What was the Company's response to this recommendation?**

20 A. Pacific Power states that using a 200 CP approach to classify costs would be
21 inappropriate, as it would diminish the impact of low-load factor customers on the
22 system. Low load-factor customers are those whose peak usage is significantly

not included in the other companies' PCAMs, see *WUTC v. Pacific Power & Light Company*, Docket UE-050684, Order 04 ¶ 93.

1 higher than their average usage; the Company states that using a 200 CP approach to
2 classify its demand costs “is not representative of the system requirements necessary
3 to meet peak demand.”¹³ The Company proposes to continue to use the SDLF
4 methodology to classify costs.
5

6 **Q. What is Staff’s position on the Company’s response to the first**
7 **recommendation?**

8 A. Upon further review, Staff concurs that the SDLF approach is preferable to the 200
9 CP approach for classifying costs. Staff recognizes that the consumption patterns of
10 low-load factor customers is a major driver of the system peak demand that the
11 Company must meet, and that the SDLF approach better captures the demands that
12 these customers impose on the system and classifies those costs appropriately.
13

14 **Q. What was Staff’s second recommendation from the previous general rate case?**

15 A. Staff recommended that Pacific Power apply a new allocation factor to its renewable,
16 non-dispatchable generation (NDG) sources. This allocation factor would recognize
17 these resources’ variable ability to contribute to system peak and proportionately
18 high energy output by allocating their costs mostly according to energy consumption.
19

20 **Q. Why did Staff make this recommendation?**

21 A. In its 2013 Integrated Resource Plan (IRP), Pacific Power determined that on
22 average, its wind resources contribute 4.2 percent of their nameplate capacity at

¹³ Direct Testimony of Joelle R. Steward, Exhibit No. ____ (JRS-1T), at 9:19-20.

1 system peak.¹⁴ Using this capacity credit, Staff recommended that the NDG Factor
2 allocate 4.2 percent of the Company's wind generation costs on a demand factor and
3 95.8 percent on an energy factor.

4 For the 2015 IRP, the Company has adopted a new methodology for
5 calculating the capacity value of its wind resources that results in a peak contribution
6 of 18.1 percent of nameplate capacity.¹⁵

7 In addition to the engineering aspects of wind generation outlined above,
8 Staff additionally noted that the NDG allocation factor would address a mismatch
9 between how the Company recovers its wind resource costs and how it passes back
10 federal tax credits generated by those resources to customers. Specifically, if the
11 Company continues recovering costs on a factor that includes a high share of
12 demand, and returning tax credits through volumetric rates, then customers with high
13 energy consumption would receive a disproportionately large share of the tax credit
14 benefits, while customers with low energy consumption would receive a
15 disproportionately small share of the tax credit benefits.¹⁶

16
17 **Q. Please summarize Pacific Power's response to Staff's second recommendation.**

18 A. The Company prepared the analysis as requested, showing the impact of an NDG
19 allocation on its seven customer classes. Compared to the Company's proposed cost
20 of service, the application of the NDG factor would reduce the Residential class' cost
21 of service by 0.5 percent and increase the remaining classes' costs of service by a

¹⁴ Pacific Power's "Integrated Resource Plan," Volume 1, April 30, 2013, at 93-94.

¹⁵ Per materials provided at the Sept. 24, 2014, meeting of Pacific Power's IRP advisory group.

¹⁶ *WUTC vs. Pacific Power & Light Company*, Docket UE-130043, Exhibit No. ___ (CTM-1T) at 16:9-18.

1 small amount, ranging from 0.07 percent (Small General Service) to 1.23 percent
2 (Street Lighting).¹⁷

3 The Company chose not to apply the NDG factor in its cost of service study
4 because the allocation factor that it uses for generation facilities “recognizes the
5 combined nature of (generation) resources that are designed to meet peak load and
6 supply the energy needs of its customers.”¹⁸ The Company goes on to assert that
7 singling out wind resources for a different allocation factor would alter the dynamic
8 of the current allocation and require Pacific Power to reassess the way it classifies all
9 of its generation resources in the Western Control Area.¹⁹ The Company appears to
10 further imply that the minor impact of the change does not justify making it.

11
12 **Q. Has the Company’s response changed Staff’s position regarding the use of the**
13 **NDG allocation factor?**

14 A. No. The NDG allocation factor more accurately reflects how wind-related expenses
15 are imposed on Pacific Power’s system. Even though its impact to rates is relatively
16 small today, the NDG allocation factor will produce more accurate rates now and in
17 the future – when wind resources will likely make up a larger percentage of Pacific
18 Power’s resource portfolio.

19
20 **Q. Please explain how the NDG allocation factor more accurately reflects system**
21 **costs.**

¹⁷ Steward, Exhibit No. ____ (JRS-1T) at 12:Table 1.

¹⁸ *Id.* at 11:7-9.

¹⁹ *Id.* at 11:10-12.

1 A. Pacific Power has acquired its WCA wind resources primarily to meet the renewable
2 portfolio standards (RPS) adopted by WCA states (Washington, Oregon, and
3 California); the Company has stated that any future wind acquisitions in the WCA
4 will be solely driven by RPS compliance needs.²⁰ Each of the WCA states has
5 adopted an energy-based standard; that is, the amount of renewable energy that a
6 utility must acquire is based on the energy it sells.²¹ In short, higher energy usage
7 results in a higher RPS target. Since it is energy usage that drives the Company's
8 need to acquire wind resources, it is logically consistent to assign the costs of wind
9 energy on the same determinant – customer energy usage. The NDG allocation
10 factor more closely allocates the costs associated with wind energy to customer
11 usage, thus following the principles of cost causation and allocation.

12
13 **Q. Is there any benefit to delaying the adoption of the NDG allocation factor?**

14 A. No. As noted above, the impact of the NDG allocation factor is relatively small
15 today, but is expected to increase with the growth of the Company's wind resource
16 portfolio. Importantly, adoption of the NDG allocation factor is in line with the
17 principle of cost causation. While the Commission has identified other policy goals
18 that may justify a divergence from this principle, such as gradualism, Staff maintains
19 that cost causation should be the starting point of the cost of service analysis. In this
20 instance, the NDG allocation factor assigns costs associated with wind energy in a
21 manner that is more reflective of why those costs were incurred. And since its

²⁰ Pacific Power 2013 Integrated Resource Plan, pg. 205.

²¹ In Washington, RCW 19.285.040(2) states that a utility's annual RPS target will be a certain percentage of its load.

1 impact on rate spread is modest, it does not conflict with gradualism or other policy
2 goals that might justify a divergence from cost causation.

3 For these reasons, I have included the NDG factor in Staff's cost-of-service
4 study, calculated to reflect the Company's updated wind capacity value of 18.1
5 percent.

6
7 **Q. What was Staff's third recommendation from the previous general rate case?**

8 A. Staff recommended that Pacific Power directly assign the costs of its corporate
9 account managers to the industrial customer classes that those account managers
10 serve.

11
12 **Q. Why did Staff make this recommendation?**

13 A. Corporate account managers are assigned to customers with loads of 750 kW or
14 greater. When one of these customers has an issue with their service, they contact
15 the corporate account manager, rather than the general customer service line that
16 serves the remaining customer classes.²² As large industrial customers are the only
17 ones who benefit from these account managers, the costs associated with the account
18 managers should be directly assigned to the large industrial customers they serve,
19 and not allocated across all customers classes as the Company has done.

20

²² *WUTC vs. Pacific Power & Light Company*, Docket UE-130043, Exhibit No. ___ (CTM-1T) at 21:8-20.

1 **Q. Please summarize Pacific Power’s response to Staff’s third recommendation.**

2 A. Pacific Power stated that it would be willing to further explore the recommendation,
3 but did not incorporate it in its cost of service study because of its minimal impact²³
4 and the “complex and burdensome” process of isolating individual cost drivers to
5 specific types of customers within the Federal Energy Regulatory Commission’s
6 Uniform System of Accounts.²⁴

7
8 **Q. What is Staff’s position on the Company’s response to the third**
9 **recommendation?**

10 A. Staff maintains its position that the costs associated with corporate account managers
11 should be directly assigned to the Large General Service customers on Schedule 48T,
12 which those account managers serve. Staff’s cost-of-service study reflects this direct
13 assignment. Staff recognizes that the Company’s analysis of this direct assignment
14 shows that the impacts on cost of service would be a fraction of a percent for each
15 class, but believes that it is clearly aligned with the principle of cost causation.

16
17 **Q. What is the net effect of Staff’s adjustments to the Company’s cost-of-service**
18 **study?**

19 A. Exhibit No. ___(JBT-3) provides a comparison of the Company’s current cost-of-
20 service study, the Company’s proposed study, and Staff’s current and proposed
21 studies.

22

²³ Steward, Exhibit No. ___(JRS-1T) at 12:13.

²⁴ *Id.* at 13:2-6.

1 **Q. How does Staff use the cost-of-service study to inform its allocation of the**
2 **revenue increase?**

3 A. An important output of the cost of service study is the parity ratio of each customer
4 class. Parity ratio measures to what degree the Company recovers its costs
5 associated with serving that class. A parity ratio of 1.0, for example, indicates that a
6 class is paying its exact cost of service, while a ratio of 1.1 indicates that a class is
7 paying 110 percent of its costs and a ratio of 0.9 indicates that a class is only paying
8 90 percent of its costs.

9 Staff considers the parity ratio of each class when determining how to
10 allocate the revenue increase. Fair rate design is premised upon each class paying a
11 fair share of its costs; therefore, Staff's proposal allocates the largest share of the
12 overall increase to the classes that are currently paying the smallest share of their
13 costs.

14
15 **Q. Has the Commission established target parity ratios?**

16 A. No. The Commission has outlined general principles for how parity ratios should be
17 considered when allocating a general rate increase across various classes, but it has
18 not prescribed a specific range into which parity ratios should fall. For example, in
19 Puget Sound Energy's last general rate case, the Commission determined that it was
20 appropriate to allocate the increase unevenly across the different classes to move
21 each class closer to its cost of service, as long as doing so did not conflict with other
22 principles, like gradualism.²⁵

23

²⁵ *WUTC vs. Puget Sound Energy*, Docket UE-111048, Order 08 (May 7, 2012) ¶ 336-337.

1 **Q. Given the Commission's direction on parity ratios, how does Staff propose to**
2 **allocate the 2.41 percent increase across the customer classes?**

3 A. Staff proposes to impose 150 percent of the increase to the Residential and Dedicated
4 Facilities classes, which have current parity ratios of 0.92 and 0.93, respectively.
5 This results in a 3.62 percent increase for each class, which would bring the
6 Residential class to a parity ratio of 0.95 and the Dedicated Facilities Class to a
7 parity ratio of 0.97. Staff also proposes to allocate 100 percent of the increase to the
8 Large General Service (> 1,000 kW) class, bringing it to a parity ratio of 1.02, and a
9 1.7 percent increase to the Large General Service (< 1,000 kW) class, bringing it to a
10 parity ratio of 1.04. Staff proposes no increases for the Small General Service,
11 Agricultural Pumping Service, and Street Lighting classes, which all have a parity
12 ratio of 1.07 or greater.

13
14 **V. RATE DESIGN**

15
16 **Q. Please outline Staff's general goals in its proposed rate design.**

17 A. Staff's rate design proposal represents an effort to strike a balance between two
18 fundamental, competing goals: ensuring more reliable recovery of fixed costs for
19 Pacific Power and establishing clear price signals for consumers in support of
20 policies established by the State of Washington and the Commission to promote
21 investments in energy efficiency and renewable energy.

22

1 Traditional rate design spreads a utility's fixed-cost recovery through the volumetric
2 rates that customers pay based on their usage. Slowing load growth, due to increased
3 end-use efficiencies and distributed generation (DG), has exposed the underlying
4 faults in this approach, as recently explained by a former New York State Public
5 Service Commissioner:

6 This traditional approach worked well when per-customer energy use was
7 growing. It produced incremental revenues that helped utilities fund new
8 investments. In the future, however, as customers opt to deploy DG and
9 other kinds of similar energy resources, per-customer kWh use will likely fall
10 below levels assumed in the electric utility's most recent rate case. This will
11 cause the utility to under-recover some of its allowed fixed costs. As DG
12 grows, such under-recovery has the potential to materially weaken the
13 utility's financial integrity and its ability to attract investor capital, which in
14 turn can lead to higher rates. To avoid this unintended outcome, we need to
15 move, over time, toward rates that recover fixed network costs through fixed
16 charges to all ratepayers.²⁶
17

18 Pacific Power is the textbook example of a utility with declining sales that has been
19 negatively affected by obsolete rate design. Since peaking in 2005, the Company's
20 annual load in Washington declined by an average of 0.67 percent per year through
21 2013. Due to a rate design that recovers much of the Company's fixed costs through
22 usage-based charges, the Company's declining load trend is likely the primary
23 reason the Company has not recovered its authorized revenue requirement since at
24 least 2006.²⁷

25 Mandatory energy conservation requirements codified in the Energy
26 Independence Act have contributed to the Company's declining load. Since the Act's
27 conservation requirements began in 2010, Pacific Power's efficiency programs have

²⁶ Robert E. Curry Jr., "The Law of Unintended Consequences." *Public Utilities Fortnightly*, March 2013, pgs. 44-48.

²⁷ Direct Testimony of Bryce R. Dalley, Exhibit No. ___ (BRD-1T) at 5:9-11.

1 saved about 205,000 MWh in Washington.²⁸ On average, those savings represent
2 1.27 percent of the utility's load each year. This is not a trivial amount; the 61,000
3 MWh that the company conserved in 2013 represent about \$6 million in foregone
4 revenue.²⁹

5 In some instances, the Commission has sought to overcome a utility's natural
6 disincentive to pursue conservation by implementing decoupling mechanisms, which
7 provide a true-up mechanism that allows a utility to recover its fixed costs regardless
8 of actual usage. PSE has such a mechanism in place; a settlement agreement filed in
9 Avista's current rate case would, if approved by the Commission, create one for that
10 company. Pacific Power does not have such a mechanism and is not requesting one
11 in this case.

12 Absent decoupling, Staff believes it is appropriate and necessary to design
13 Pacific Power's rates in a manner that will shift a greater share of the Company's
14 fixed-cost recovery from the volumetric component of a customer's bill to the basic
15 charge. This approach will provide a proxy to a decoupling mechanism and insulate
16 the Company against the risk of under-recovering its fixed costs in an era of
17 uncertain load. Staff also notes that the decoupling mechanism granted to Puget
18 Sound Energy has been the subject of controversy and considerable additional
19 evaluation and measurement work; Staff's proposed rate design in this case may

²⁸ See *In the Matter of PacifiCorp d/b/a Pacific Power & Light Company's 2010-2011 Biennial Conservation Target under RCW 19.285.040*, Docket UE-100170, Order 03 ¶ 5 and *In the Matter of Pacific Power & Light Company's 2012-2013 Biennial Conservation Target Under RCW 19.285.040*, Docket UE-111880, Order 04 ¶ 12.

²⁹ This figure assumes that the 61,060 MWh that the Company conserved in 2013 were saved at the margin and therefore would have been billed at the company's second block, which is currently 9.817 cents/kWh.

1 provide a more efficient means of pursuing the underlying policy goals that
2 decoupling addresses.

3 It is important that the Commission take steps now that will reduce the
4 natural disincentive that Pacific Power faces when considering investment in energy
5 efficiency, particularly because complying with the proposed carbon emission
6 reduction goal set forth by the Environmental Protection Agency may require
7 Washington utilities to accelerate their conservation programs.³⁰

8 While shifting a greater share of fixed-cost recovery to the basic charge is
9 aligned with Staff's first goal of ensuring more reliable recovery of fixed costs for
10 Pacific Power, it is in direct conflict with the second goal of creating price signals for
11 customers that encourage investments in energy efficiency and distributed energy.

12 Inclining block rates, which increase the per-kWh charge as consumption
13 increases, are an effective approach to encouraging efficient usage, because they
14 create a consistent price signal for all customers and require minimal overhead costs
15 to implement.³¹ To effectively encourage high users to become more efficient, there
16 must be enough of a spread between the block rates for customers to perceive the
17 price signal.³² However, depending on how they are designed, inverted block rates
18 can undermine the goal of ensuring a utility more certainty in its cost recovery if
19 customers respond to the price signal and reduce their usage. Conversely, allowing a

³⁰ The EPA's proposed Clean Power Plan consists of four blocks that states may use to meet its proposed emissions reduction goals. Block four consists of energy efficiency programs; each state's target was calculated with an assumed conservation rate of 1.5 percent of its load. As I stated on the previous page, Pacific Power's efficiency programs currently save about 1.27 percent of its Washington load. Should the state craft a compliance plan that includes the full 1.5 percent savings from the efficiency block, Pacific Power would likely be asked to accelerate its conservation programs.

³¹ Admad Faruqi, "Inclining Toward Efficiency." *Public Utilities Fortnightly*, August 2008.

³² Adam Pollock and Evgenia Shumilkina, "How to Induce Customers to Consume Energy Efficiently: Rate Design Options and Methods." National Regulatory Research Institute, January 2010.

1 utility to recover more of its costs through the basic charge reduces the portion of a
2 bill that customers can control by becoming more efficient, which could discourage
3 efficient behavior.

4 Staff has considered these competing goals and strived to develop a rate
5 design that strikes a balance between them. Staff's rate design achieves this balance
6 by increasing the size of the monthly basic charge to provide the Company with
7 some insulation from the impacts of declining load, while adjusting the inclining
8 block structure to offset some of that increase for ratepayers and adding a third block
9 to provide a stronger price signal for high residential users to become more efficient.
10 In tandem, Staff's rate design balances the impact of its proposed changes on both
11 the Company and ratepayers.

12
13 **Q. Why does Staff propose to increase the monthly basic charge for residential**
14 **customers from \$7.75 to \$13.00?**

15 A. As I explained above, in the absence of a decoupling mechanism to reduce Pacific
16 Power's risk of under-recovering fixed costs due to declining load, it is appropriate
17 to shift the distribution of the Company's cost recovery toward fixed sources of
18 recovery, such as the monthly basic charge. Staff's proposal of \$13.00 reflects the
19 impact of moving the Residential customer class' share of line transformer costs into
20 the basic charge. The basic charge is intended to recover costs that do not vary based
21 on a customer's use; that is, the costs that the Company incurs when a customer
22 connects to the grid. Line transformers are a fixed component of the distribution
23 system without which a residential customer cannot receive service, and the cost of a

1 transformer does not vary based on usage. Recovering transformer costs through the
2 basic charge accomplishes the goal of providing the Company with more stable
3 recovery of fixed costs while remaining aligned with cost-causation principles.
4

5 **Q. What are the sizes and rates associated with the residential blocks in Staff's**
6 **proposal?**

7 A. Staff is proposing the following residential block sizes and rates:

- 8 • Block 1: 0-800 kWh at 6.472 cents per kWh
- 9 • Block 2: 801-1700 kWh at 9.17 cents per kWh
- 10 • Block 3: 1701 kWh and up at 11.996 cents per kWh

11 I provide a side-by-side comparison of the monthly residential bill impact on
12 residential users under Pacific Power's current rate structure, the Company's
13 proposed structure, and Staff's proposed and alternately proposed structures in
14 Exhibit No. ___(JBT-4).

15
16 **Q. Please explain Staff's rationale for the three-block rate design and placement of**
17 **the blocks.**

18 A. Staff's three-block proposal serves two key purposes: to create a clearer price signal
19 for residential customers to be more efficient and to follow the principles of cost
20 causation by assigning a greater share of Staff's proposed increase to high-use
21 customers, who impose greater demands (and therefore costs) on the Company's
22 system.

1 Staff proposes to increase the size of the first block from 600 kWh to 800
2 kWh because the first block should correspond to customers' inelastic usage – that
3 is, the usage required to support basic living necessities such as refrigeration,
4 cooking, and hot water. According to data compiled by the Housing and Urban
5 Development Administration, this corresponds to a range of 700 to 850 kWh.³³ Staff
6 elected to place the first block at 800 kWh for simplicity of billing and because
7 Pacific Power's Washington customers have generally higher average usage than
8 other utilities in the state; setting the block above the midpoint of HUD's range (775
9 kWh) is reflective of local system usage characteristics.

10 Increasing the size of the first block also recognizes the fact that most
11 customers have limited capacity for efficiency gains when it comes to basic needs
12 such as refrigeration, cooking, and hot water, so there would be little to gain by using
13 a price signal to motivate more efficient behavior in this range.

14 Staff proposes to place the second block at a range of 801 to 1700 kWh to
15 reflect average usage of the system. If the intent of the third block is to provide a
16 price signal for high users, then the second block should be placed in a position that
17 does not impose additional costs on average users. The average Washington
18 residential customer of Pacific Power uses about 1,300 kWh per month on an annual
19 basis, but average usage in the winter (November through February) climbs to 1,700
20 kWh per month. Setting the end of the second block at 1,700 kWh recognizes that
21 most of Pacific Power's Washington customers rely on electric sources of heating,

³³ Housing and Urban Development Administration Guidebook, Chapter 18, pg. 18-5. Available at <http://www.hud.gov/offices/adm/hudclips/guidebooks/7420.10G/7420g18GUID.pdf>.

1 and allows for higher average usage in winter months without a dramatic increase in
2 rates.

3 Under Staff's proposal, rates for all usage between 600 kWh and 1,700 kWh
4 would be reduced from their current levels. For the average customer using 1,300
5 kWh per month, this corresponds to a benefit of \$6.69 per month that offsets the
6 entire basic charge increase and the higher rate for the first block that Staff proposes.
7 For the average customer using 1,700 kWh per month during the winter, the change
8 in the size and placement of the blocks would create a monthly benefit of \$7.46.

9 The net effect of Staff's proposals are that the average customer using 1,300
10 kWh would see a bill decrease of \$3.04 per month, or about 2.7 percent, and the
11 customer with average winter use of 1,700 kWh would see a decrease of \$5.63 per
12 winter month, or 3.7 percent.

13
14 **Q. If Staff's proposal would decrease rates for the average residential customer,**
15 **then how would Staff's proposed 3.62 percent increase be distributed across the**
16 **Residential class?**

17 A. Exhibit No. ___ (JBT-4) shows how the increase would be distributed across
18 customers according to their usage. Under Staff's proposal, all residential customers
19 using between 850 kWh and 1,900 kWh would see decreases in their monthly bills.
20 Customers using fewer than 850 kWh would see increases that grow as usage
21 decreases, due to these customers paying the increased basic charge but not receiving
22 the offsetting reductions associated with the placement and rates of the volumetric
23 blocks. The highest percentage increase would be experienced by customers that use

1 0 kWh in a month, who would see a bill increase of \$5.25 (the full basic charge
2 increase), or 67.7 percent. However, this is not unreasonable. The delivery system
3 remains in place ready to serve those customers at all times.

4 Toward the other end of the spectrum, customers using 2,000 kWh per month
5 would see an increase of \$0.91 per month, or 0.5 percent. The magnitude of the
6 increase grows with usage after that point. For example, a customer using 4,000
7 kWh per month (approximately three times the class average) would see an increase
8 of \$44.49, or 11.7 percent.

9
10 **Q. How does Staff anticipate that high-use customers would respond to the price
11 signal its proposed rate structure would create?**

12 **A.** In economics, the relationship between the price of a good and the amount of that
13 good that consumers purchase is known as the price elasticity of demand. This
14 figure is given as a percentage, which can be used to predict the rate at which
15 consumers will reduce their purchases of a good if the price increases by a given
16 amount. The formula for calculating the price elasticity of demand is the change in
17 how much consumers purchase divided by the change in price. For example, if a
18 given item increases in price by 10 percent and consumers buy 10 percent less of that
19 item as a result, then the price elasticity of demand for that item is -1 (-10% change
20 in demand / 10% change in price). Price elasticities of demand are generally
21 negative, since the normal supply/demand relationship indicates that purchases of a
22 good decrease as the price increases.

1 Items that have an elasticity between 0 and -1 are called inelastic goods –
2 those for which the consumer response to a price change is smaller than the price
3 change. For example, if the price of an item increases by 10 percent, but purchases
4 of the item only decrease by 5 percent, then elasticity is only -0.5 and demand for the
5 item is considered inelastic. Electricity generally falls into this category because of a
6 lack of readily available substitutes. When the price increases, consumers may
7 change their behavior to use less electricity, such as turning off lights when leaving a
8 room. But there is little that they can do to immediately reduce their usage by a
9 significant amount.

10 Over time, however, consumers have more options. They may be able to
11 invest in more efficient appliances or switch to different fuels for their home energy
12 needs. Recognizing this fact, economists generally measure the price elasticity of
13 demand separately for the short term and the long term.

14 Staff has obtained short-term and long-term elasticities for residential
15 customers in Washington from a report prepared for the National Renewable Energy
16 Laboratory in 2006.³⁴ In Exhibit No. ___(JBT-4), I have used these elasticities to
17 estimate by how much Pacific Power’s customers might reduce their electricity
18 usage if Staff’s proposed rates are implemented. This analysis projects that if Staff’s
19 proposed rate design is implemented, Pacific Power’s residential customers can be

³⁴ Bernstein, M.A. and J. Griffin, “Regional Differences in the Price-Elasticity of Demand for Energy.” National Renewable Energy Laboratory, 2006. For Washington, the researchers calculated a short-term price elasticity for electricity of -0.079 and a long-term price elasticity of -0.161.

1 expected to reduce their usage in the first year by 0.23 percent; over the long term,
2 that figure will increase to 0.47 percent.³⁵

3
4 **Q. How did you determine those figures?**

5 A. I conducted an analysis based on the billing groups defined by the Company in its
6 bill study,³⁶ which groups monthly residential bills in 100-kWh increments up to
7 3,000 kWh/month, then in a 3,000-3,500 kWh group and a 3,500+ kWh group. I
8 looked at all customers with usage above 2,000 kWh, since those are the customers
9 that would see an increase under Staff's proposal. I took all of the Company's
10 groupings from the bill study and determined the increase that each group would face
11 under Staff's proposal. For the 3,000-3,500 kWh group, I used the average increase
12 for all customers within that range; for the 3,500+ kWh group, I used the average
13 increase on all customers with usage between 3,500 kWh and 6,000 kWh.³⁷

14 For each group, I began with the percentage increase that the group would
15 face under Staff's proposed rates. Knowing the change in price and the elasticity,
16 solving for the projected reduction in usage for each class was a matter of simple
17 algebra.³⁸ I then applied the projected reduction for each group to the average
18 monthly usage for the group to determine the average reduction in usage per bill
19 within that group, and then multiplied that number by the number of bills in the
20 group to determine the aggregate reduction for the group. Finally, I summed all the

³⁵ For the purposes of this analysis, short-term is defined as the first year and long-term is defined as longer than one year.

³⁶ Company response to UTC Data Request 48.

³⁷ Average usage for customers in the 3,500+ group is 4,497 kWh; analyzing a range between 3,500 and 6,000 kWh likely represents most of the customers that fall into this category and limits the ability of outlying users with extremely high usage to skew the analysis.

³⁸ If $Elasticity = \Delta Demand / \Delta Price$, then $\Delta Demand = Elasticity * \Delta Price$.

1 groups and divided the total reduction by the Company's total load per the bill study,
2 which yielded a projected reduction of 0.23 percent. I repeated those steps with the
3 long-term elasticity to calculate the total long-term reduction of 0.47 percent.

4 While these reductions may appear trivial, they represent a fairly significant
5 source of savings for Pacific Power and its customers. As a point of reference, the
6 Company's Washington conservation programs during the 2012-2013 biennium
7 saved an average of 55,962 MWh per year at an average annual cost of about \$10
8 million, or \$178 per MWh. If the long-term savings of 0.49 percent are achieved,
9 that represents 7,660 MWh per year of savings (about 14 percent of the Company's
10 annual average) that could be achieved with no additional expenditures on
11 conservation programs.

12 I should point out that these figures are only rough projections; there are a
13 number of other factors that will affect the total reduction in electricity usage.
14 Staff's projection should be interpreted as an upper-bound estimate of the reduced
15 usage that may occur.

16
17 **Q. How does Staff's proposal address the increased risk that the Company faces if**
18 **customers respond to this price signal and reduce their usage as Staff has**
19 **projected?**

20 A. Staff addresses this concern in the way rates are designed. As I show in Exhibit No.
21 ____ (JBT-4), there are few fixed charges recovered in the third block. Of the 11.996-
22 cent rate for this block, 58 percent is based on energy costs, so any reduction in
23 usage in this block should strongly correlate with a reduction in the Company's

1 energy-based expenses such as fuel and purchased power. Under Staff's proposal,
2 only about 14 percent of the Company's fixed costs would be recovered in the
3 third block, so the risk of under-recovering fixed costs as a result of reduced usage in
4 the third block is low.³⁹ In fact, if Staff's long-term projection of 0.47 percent
5 reduced usage is realized, then the 7,660 MWh that would be saved in the third block
6 only represent 2.9 percent of total usage in the block. Multiplying the 2.9 percent
7 reduction by the 14 percent of fixed costs that are recovered in the third block, Staff
8 finds that only about 0.4 percent of the Company's fixed costs are at risk as a result
9 of the potential for reduced usage created by Staff's proposed rate design. That
10 equates to about \$373,000, or 0.1 percent of Staff's proposed overall revenue
11 requirement.

12 Should the Commission adopt Staff's proposed rate design and Pacific Power
13 remains concerned by the third block's potential impact on its fixed-cost recovery,
14 Staff recommends that the Commission invite the Company to file a revenue-neutral
15 cost-of-service/rate design proceeding. If customer response to the proposed rate is
16 greater than anticipated, Pacific Power can request to redesign rates as needed to
17 provide greater certainty in its fixed-cost recovery.

18
19 **Q. Is Staff proposing a special rate for low-income customers?**

20 A. Not as part of its primary proposal. Staff believes its proposed rate design will allow
21 the Company to continue to address the needs of its low-income consumers through
22 its existing program, and that there is no need for additional rates specifically

³⁹ For the purposes of this analysis, I define fixed costs as all costs other than the energy component of generation costs.

1 targeted at low-income customers at this time. As I noted before, Staff's proposed
2 rate design would create a monthly bill decrease for all customers whose usage falls
3 between 850 and 1,900 kWh. As seen in Exhibit No. ___(JBT-5), 47 percent of all
4 low-income bills fell within this range during the test period. Staff's proposal would
5 allow the Company to continue to operate its low-income program as a credit against
6 all usage above a certain level during winter months, though Staff recommends that
7 the Company and its implementing partners re-evaluate where that level is set based
8 on the outcome of this case.

9 However, Staff recognizes the potential benefits associated with the
10 Company's proposal to impose a smaller basic charge for low-income customers,
11 and has prepared an alternate recommendation based on that proposal. I provide a
12 side-by-side comparison of this alternate recommendation, Staff's primary
13 recommendation, the Company's recommendation and the current rates in Exhibit
14 No. ___(JBT-4). Under staff's alternate recommendation, the basic charge for low-
15 income customers on Schedule 17 would only increase to \$8.55; that smaller basic
16 charge would be offset by an increase of the basic charge for all other residential
17 customers to \$13.20 per month (an incremental increase of \$0.20 per month, or \$2.40
18 per year). The size and pricing of the volumetric blocks would be the same as in
19 Staff's original proposal. If implemented by the Commission, this alternate proposal
20 would create a year-round benefit for low-income customers equal to \$4.45 per
21 month, or \$53.40 per year. As Pacific Power's current low-income assistance
22 program is only in effect during the winter months, this proposal would increase the

1 program's reach without additional overhead expense and with minimal shifting of
2 costs to other residential customers.

3

4 **Q. Please summarize Staff's proposed rates for non-residential customers.**

5 A. Staff's proposal would impose no increase on the three customer classes that are
6 already paying well above their cost of service: Small General Service, Agricultural
7 Pumping Service, and Street Lighting.

8 The three other non-residential classes – Dedicated Facilities and the two
9 Large General Service classes – would receive increases varying between 1.7 percent
10 and 3.62 percent. For these classes, Staff has allocated the increase evenly across the
11 usage-based rates within the class, except for the basic charge for the Dedicated
12 Facilities class. Aside from the different rates arising from Staff's lower revenue
13 requirement and cost-of-service study adjustments, Staff has made no significant
14 adjustments to the Company's proposed rates for these classes. I summarize Staff's
15 proposed rates for all customer classes in Exhibit No. ____ (JBT-4).

16

17 **Q. Did Pacific Power raise any other issues in its proposed rate design?**

18 A. Yes. The Company indicated that it intends to propose a different rate structure for
19 residential customers with distributed generation (DG) in its next general rate case
20 filing, and provided a brief outline of the proposal.

21

22 **Q. Please summarize Pacific Power's anticipated rate design proposal for**
23 **residential DG customers.**

1 A. The Company indicated that it expects to propose a three-part rate design for
2 residential DG customers, similar to the rate design for commercial and industrial
3 customers.⁴⁰ A three-part rate design includes the basic charge and volumetric usage
4 charge that residential customers already pay, but adds a demand charge that assesses
5 an additional fee based on the customer's peak usage during the billing cycle.

6

7 **Q. What justification does the Company provide for this approach?**

8 A. The Company states that imposing a demand charge on residential DG customers
9 would provide them with two important incentives: to "(1) avoid rapidly ramping up
10 electricity purchases as distributed generation production wanes or is unavailable;
11 and (2) reduce electricity purchases at peak times."⁴¹ The Company's arguments
12 appear to rely on studies that have been done in other jurisdictions, which show that
13 as solar DG penetration rates increase, utilities face a situation in which DG
14 customers offset a large share of the utility's load during the day while the sun is
15 shining, but then require the utility to rapidly bring on resources in the late afternoon
16 as solar production wanes and the utility must replace that lost power and ramp up to
17 meet its daily peak, which occurs in the evening hours. This load shape that has
18 come to be widely known as "The Duck Curve."⁴²

19 The Company concludes that a demand charge would provide residential DG
20 customers with a price signal that would incentivize them to use less energy as their

⁴⁰ Direct Testimony of Joelle R. Steward, Exhibit No. ___ (JRS-1T), at 26: 8-10.

⁴¹ *Id.*, at 26: 5-8.

⁴² For a summary of this issue, see "Fast Facts," published by the California Independent System Operator and available at www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

1 solar production fades out, which would decrease the utility's daily peak and the rate
2 at which it would need to bring resources online to meet that peak.

3
4 **Q. Please summarize Staff's response to the Company's anticipated DG rate
5 proposal.**

6 A. Imposing a demand rate on residential DG customers would be inappropriate
7 because it does not reflect the operations of Pacific Power's WCA system, it would
8 be unduly discriminatory, and Staff's proposed rate spread would address many of
9 the potential cost recovery issues associated with DG. As a result, Staff recommends
10 that the Commission indicate that such a proposal would not be acceptable and
11 should not be included in the Company's next general rate case.

12 Staff also notes that distributed generation is the subject of ongoing
13 Commission workshops. This issue may be better addressed on an industry-wide
14 basis, not as company specific.

15
16 **Q. Please explain why the demand rate for residential DG customers would not
17 reflect the operations of Pacific Power's WCA system.**

18 A. As I stated above, the Duck Curve and similar studies that have been done in other
19 states represent the challenges that DG poses to an evening-peaking utility, which
20 must rapidly add resources over a small window to replace declining solar output and
21 meet the daily peak. However, in the WCA, Pacific Power is generally not an
22 evening-peaking utility, and is not as subject to the issues represented in the Duck
23 Curve.

1 Exhibit No. ___ (JBT-6) shows Staff’s comparison of the Company’s top 200
2 load hours against the recorded sunrise and sunset times for Yakima in 2013, which
3 shows that of the top 200 hours that the Company served in the WCA during the test
4 year, 124 (62 percent) occurred during daylight hours, including 12 of the top 13
5 hours.⁴³ It is reasonable to conclude, therefore, that during peak hours, a DG
6 customer is more likely to be producing energy that helps Pacific Power meet load
7 than to be increasing energy usage and contributing to a steeper ramp that the
8 Company must meet. Designing a rate around the assumption that solar production
9 is decreasing or unavailable at the time of peak would therefore be erroneous.

10 Staff also notes that Pacific Power only had 141 residential DG customers in
11 its Washington territory in December 2013, which represents 0.1 percent of its
12 residential customer class. The Company simply does not have enough DG
13 customers on its Washington system, in Staff’s opinion, to affect Company
14 operations and justify a targeted rate treatment.

15 Staff recognizes that the Company is preparing a detailed new load study that
16 will, among other things, attempt to quantify the impact of residential DG on
17 Company operations.⁴⁴ Staff is open to considering a special rate treatment for
18 residential DG customers if the load study warrants, but given the current state of
19 operations, Staff believes that the Company would face a high burden of proof in

⁴³ I compared the top 200 hours as provided in Pacific Power’s cost-of-service study, Exhibit No. ___ (JRS-4), “200 Top Hrs” tab, against the recorded sunrise and sunset times for Yakima in 2013 as provided by www.sunrisesunset.com. I did not include partial daylight hours when counting the number of peak hours that occurred during daylight. For example, if a peak occurred during the 4 p.m. hour and the sun set at 4:30 p.m., I did not count that as a daylight peak hour.

⁴⁴ Direct Testimony of Joelle R. Steward, Exhibit No. ___ (JRS-1T), at 25: 16 – 26: 2.

1 justifying such an approach, and is in fact likely to discover other interactions in
2 residential customer usage that may reverse its assumptions.

3
4 **Q. Please explain why the demand rate for residential DG customers would be**
5 **unduly discriminatory.**

6 A. The Company's second point to justify the proposal is that it would signal DG
7 customers to "reduce electricity purchases at peak times."⁴⁵ Staff points out,
8 however, that load is the sum of every individual customer's usage at any given
9 point, and the Company and its customers receive the same benefit in reduced usage
10 from any point on the system. Singling out DG customers for an additional rate
11 designed to encourage greater efficiency at peak is discriminatory and is another
12 reason that the Commission should tell Pacific Power that the approach the Company
13 is considering for residential DG customers is not acceptable.

14
15 **Q. Please explain how Staff's proposed rate spread would address many of the**
16 **potential cost recovery issues associated with DG.**

17 A. As I previously discussed, when a utility recovers a significant share of its fixed
18 costs through volumetric rates, then a reduction in a customer's usage – be it from
19 DG or conservation or some other factor – means that the utility recovers fewer of
20 those fixed costs. If fixed costs continue to be recovered primarily through
21 volumetric rates, then customers that are unwilling or unable to participate in DG
22 and conservation programs will bear an unequal share of any ensuing rate increases
23 and effectively subsidize customers who have DG and/or are more efficient. This

⁴⁵ *Id.*, at 26: 7-8.

1 issue does not arise from the existence of DG or conservation programs; rather, these
2 programs simply exacerbate the underlying problems that exist in legacy rate design.

3 Staff's proposed rate design for residential customers addresses this concern
4 by weakening the link between customer usage and the Company's fixed-cost
5 recovery. By designing a basic charge that includes a larger share of fixed cost and
6 limiting the share of fixed costs that are recovered in the third block to 14 percent,
7 Staff believes that its proposed rates insulate the Company against the impacts of
8 reduced usage associated with self-generation and efficient behavior.

9

10 **Q. Does this conclude your prepared testimony?**

11 **A. Yes.**

12