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# BEFORE THE PUBLIC UTILITY COMMISSION

# OF THE STATE OF OREGON

# UE ___

# 2017 Decoupling

## PORTLAND GENERAL ELECTRIC COMPANY

**Direct Testimony and Exhibits of**

*Jay Tinker*
*Marc Cody*

**March 1, 2016**

# Table of Contents

# I. Introduction

**Q. Please state your names and positions.**

A. My name is Jay Tinker. I am the Director of Regulatory Affairs for PGE.

My name is Marc Cody. I am a Senior Analyst in Pricing and Tariffs for PGE. Our qualifications are described in Section III.

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

A. The purpose of our testimony is to request a renewal of PGE's Schedule 123 Decoupling Adjustment, with a minor modification, for an additional three years, from 2017-2019. PGE Exhibit 101 contains the proposed Schedule 123 changes with an effective date of January 1, 2017.

**Q. What is the minor modification you propose to Schedule 123?**

A. We propose to discontinue the current Lost Revenue Recovery Adjustment (LRRA) in favor of a revenue-per-customer form of decoupling for Schedule 83/583 (31-200 kW) customers, effective January 1, 2017.

**Q. Do you propose to use the volumetric and fixed charge revenues for Schedules 7, 32 and 83 that were determined in PGE's last general ratecase, UE 294?**

A. Yes. We will include the appropriate increment for the Carty generating station when it becomes operational. In addition, we propose to use the UE 294 load forecast for determining usage-per-customer for Schedules 7, 32, and 83 until such time as new usage-per-customer metrics are determined in a subsequent general rate proceeding.

**Q. Do you propose that the decoupling mechanism calculations continue to be on a weather-adjusted basis?**

A. Yes.

**Q. Do you propose to keep the current Secondary Fixed Charge percentage for Schedule 7?**

A. Yes. PGE and stakeholders successfully resolved this issue in UE 262. Proposing to maintain the Schedule 7 Secondary Fixed Charge also addresses the concerns raised by the Citizens Utility Board of Oregon (CUB) in both dockets UG 287 and UG 288 regarding the consumption of new residential customers, and their effect on decoupling results.

**Q. Before discussing the specific modification to Schedule 123, please provide a summary of the decoupling results for Schedules 7 and 32 since Schedule 123 was originally adopted.**

A. Table 1 below provides an annual summary of the results through 2015 for Schedules 7 and 32 inclusive of interest (negative amounts are refunds to customers):

| Year | Schedule 7 | Schedule 32 |
|---|---:|---:|
| 2009 | ($2,517,142) | $2,026,052 |
| 2010 | $4,893,584 | $2,451,050 |
| 2011 | $416,537 | ($2,420,330) |
| 2012 | $2,567,984 | ($2,393,248) |
| 2013 | $2,587,984 | ($899,525) |
| 2014 | ($3,978,551) | ($1,323,509) |
| 2015 | ($8,088,353) | ($1,450,951) |
| Totals | ($4,118,561) | ($4,010,470) |

**Q. Generally, revenue decoupling is contingent on a utility supporting the implementation of energy efficiency measures. Could you please broadly state some of the actions PGE performs to promote energy efficiency for its customers?**

A. PGE continually supports energy efficiency (EE) funding requests from the Energy Trust of Oregon (ETO) through PGE's Schedule 109. In addition, PGE promotes EE through its website, bill inserts, and customer newsletters. On an ongoing basis, PGE conducts targeted commercial and residential marketing campaigns encouraging customers to participate in ETO programs. In partnership with the ETO, PGE works directly with small and mid-size business customers to help them identify and implement energy efficiency projects. Furthermore, PGE works closely with the ETO in order to implement future estimates of EE activity in its Integrated Resource Plans.

## II. Schedule 123 Modification

**Q. Why do you propose to eliminate the LRRA and partially replace it with a revenue-per-customer form of decoupling for Schedule 83/583?**

A. There are several reasons why we propose this:

First, we propose this in order to explore the ramifications of revenue-per-customer decoupling for large nonresidential customers. Electric and gas utilities in Washington have recently adopted revenue-per-customer forms of decoupling for larger commercial customers. In addition, gas companies in Oregon either currently employ or have stipulated to employ decoupling for larger commercial customers. Implementing a revenue-per-customer form of decoupling for Schedule 83/583 allows PGE to more closely align with what appears to be a regional trend, albeit on an exploratory basis.

Second, by eliminating the LRRA, we will no longer be dependent upon the Annual Reports provided by the Energy Trust of Oregon (ETO) for calculation of a portion of Schedule 123. In past years, the ETO provided the allocation of Senate Bill 1149 and Senate Bill 838 EE savings late in the year, necessitating PGE to request a filing date of November 1 for amortizing prior year results.

Third, potential legislative resolutions to UM 1713, Investigation into Large Customer Energy Efficiency, could change the manner in which PGE and the ETO account for the projection and attribution of EE. Currently, the LRRA is predicated upon PGE being able to project the amount of test-year EE measures occurring from a specific source of funding in a general rate proceeding, and then comparing this projection to the actual EE measures attributed to that source of funding. Potential legislative changes will likely make this form of projection and subsequent attributive true-up obsolete. Hence, it is preferable to anticipate changes in how EE is accounted for as soon as possible.

**Q. Does eventually eliminating the LRRA mean that PGE could implement the decoupling results more rapidly than it currently does?**

A. Yes. Although the proposed Schedule 123 contains no changes in the Time and Manner of Filing section, PGE is open to eventually changing the timing of amortization. Conceivably, without the LRRA, PGE could implement the decoupling results as early as May of the following year if necessary.

**Q. Do you propose to separately track the Schedule 83/583 accruals and attribute these accruals to Schedule 83/583 customers?**

A. Yes. We propose to maintain separate balancing accounts for Schedules 7, 32, and 83 such that the Schedule 83/583 accruals are attributed to Schedule 83/583 customers.

**Q. What are the volumetric and fixed charge values for Schedule 83/583?**

A. Before inclusion of Carty, the values from UE 294 are 3.634 cents/kWh and $772.18 respectively. The calculation of the values above is contained in the work papers accompanying this filing.

**Q. Do you propose to include demand charges in the calculation of the Schedule 83/583 decoupling adjustment?**

A. No. Although the RAP publication, *Revenue Regulation and Decoupling: A Guide to Theory and Application*, implies that it is appropriate to include demand charges[1], we do not do so. At this point in time we prefer to only include fixed costs that are recovered through volumetric charges in the Schedule 83/583 limited decoupling mechanism.

[1] Pages 18-19.

**Q. What is the energy consumption of customers currently subject to the provisions of the LRRA and how does this energy consumption compare to the energy consumption of Schedule 83 customers?**

A. PGE estimates that customers subject to provisions of the LRRA consume approximately 6.1 million MWh[2] and, based on PGE's UE 294 Compliance Filing, Schedule 83 customers consume approximately 2.9 million MWh.

**Q. What would the 2014 and 2015 results have been had PGE implemented revenue-per-customer decoupling for Schedule 83/583?**

A. Based on annual cycle sales, PGE estimates that in 2014, it would have refunded to Schedule 83 customers approximately $253,000 and in 2015 would have collected approximately $14,000. PGE Exhibit 102 contains the analysis related to the 2014 and 2015 figures above.

**Q. What have been the results of the LRRA since it was adopted in 2009?**

A. For the 2009-2014 periods, the LRRA has resulted in collections from applicable customers of approximately $2.7 million. The yearly details are provided in the work papers accompanying this testimony.

**Q. Why do you propose to keep the LRRA language in Schedule 123?**

A. We propose to keep the language related to the LRRA because PGE will still need to incorporate the amortization of the 2015 and 2016 LRRA results in 2017 and 2018 respectively.

**Q. Could you please briefly summarize what you are proposing for Schedule 123 effective January 1, 2017?**

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[2] PGE Advice No. 15-25.

A. 1) We propose to extend PGE's current limited revenue-per-customer form of decoupling for Schedules 7 and 32 for an additional three years, 2017-2019.

2) We also propose to replace PGE's current LRRA mechanism for large nonresidential customers with a limited revenue-per-customer form of decoupling for Schedule 83/583.

# III. Qualifications

**Q. Mr. Tinker, please state your educational background and qualifications.**

A. I received a Bachelor of Science degree in Finance and Economics from Portland State University in 1993 and a Master of Science degree in Economics from Portland State University in 1995. In 1999, I obtained the Chartered Financial Analyst (CFA) designation. I have worked in the Rates and Regulatory Affairs department at PGE since 1996.

**Q. Mr. Cody, please state your educational background and qualifications.**

A. I received a Bachelor of Arts degree and a Master of Science degree from Portland State University. Both degrees were in Economics. The Master of Science degree has a concentration in econometrics and industrial organization. Since joining PGE in 1996, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on cost of capital estimation, marginal cost of service, rate spread and rate design, and tariff administration.

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

A. Yes.

# List of Exhibits

| PGE Exhibit | Description |
| --- | --- |
| 101 | Proposed Schedule 123 Changes |
| 102 | Schedule 83/583 2014 and 2015 Decoupling Analysis |

# SCHEDULE 123
# DECOUPLING ADJUSTMENT

## PURPOSE

This Schedule establishes balancing accounts and rate adjustment mechanisms to track and mitigate a portion of the transmission, distribution and fixed generation revenue variations caused by variations in applicable Customer Energy usage.

## AVAILABLE

In all territory served by the Company.

## APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except those Nonresidential Customers whose load exceeded one aMW at a Point of Delivery during the prior calendar year or those Nonresidential Customers qualifying as a Self-Directing Customer. Customers so exempted will not be charged the prices contained in this schedule.

## DEFINITIONS

For the purposes of this tariff, the following definition will apply:

**Energy Efficiency Measures (EEMs)** – Actions that enable customers to reduce energy use. EEMs can be behavioral or equipment-related.

**Self-Directing Customer (SDC)** - Pursuant to OAR 860-038-0480, to qualify to be a SDC, the Large Nonresidential Customer must have a load that exceeds one aMW at a Site as defined in Rule B and receive certification from the Oregon Department of Energy as an SDC.

## SALES NORMALIZATION ADJUSTMENT (SNA)

The SNA reconciles on a monthly basis, for Customers served under Schedules 7, 32, ~~and~~ 532, 83, and 583, differences between a) the monthly revenues resulting from applying distribution, transmission and fixed generation charges (Fixed Charge Energy Rate) of 7.230 cents/kWh for Schedule 7, ~~and~~ 6.529 cents/kWh for Schedules 32 and 532, and 3.634 cents/kWh for Schedules 83 and 583 to weather-normalized kWh Energy sales, and b) the Fixed Charge Revenues that would be collected by applying the Monthly Fixed Charge per Customer of $61.14 per month for Schedule 7, ~~and~~ $95.89 per month for Schedules 32 and 532, and $772.18 for Schedules 83 and 583 to the numbers of active Schedule 7, ~~and~~ Schedule 32 and 532, and Schedule 83 and 583 Customers, respectively, for each month. For Schedule 7, a Secondary Fixed Charge equal to 70% of the Monthly Fixed Charge will be used to calculate Fixed Charge Revenues for actual customer counts that exceed the projected customer counts used to establish base rates in a general rate review. The Schedule 7 Secondary Fixed Charge is $42.80.

**SCHEDULE 123 (Continued)**

SALES NORMALIZATION ADJUSTMENT (SNA) (Continued)

The SNA will calculate monthly as the Fixed Charge Revenue less actual weather-adjusted revenues and will accrue to the SNA Balancing Account. The monthly amount accrued may be positive (an under-collection) or negative (an over-collection). The SNA is divided into sub-accounts so that net accruals for Schedule 7 will track separately from the net accruals for Schedules 32 and 532, and 83 and 583.

**NONRESIDENTIAL LOST REVENUE RECOVERY ADJUSTMENT (LRRA)**

For EEMs installed prior to 2017, ~~T~~the Nonresidential Lost Revenue Recovery Adjustment is applicable to all customers except those served under Schedules 7, 32 and 532 or as otherwise exempted above. Nonresidential Lost Revenue Recovery amounts will be equal to the reduction in distribution, transmission, and fixed generation revenues due to the reduction in kWh sales as reported to the Company by the Energy Trust of Oregon, resulting from EEMs implemented during prior calendar years attributable to EEM funding incremental to Schedule 108, adjusted for EEM program kWh savings incorporated into the test year load forecast used to determine base rates. Also included are differences in actual energy savings from a test year forecast associated with the conversion to LED streetlighting in Schedule 95 reported by the Company. When base rates are adjusted in the future as a result of a general rate review, the test year load forecast used to determine new base rates will reflect all energy efficiency kWh savings that have been previously achieved. The cumulative kWh savings are eligible for Lost Revenue Recovery until new base rates are established as a result of a general rate review; the kWh base is then reset to equal the amount of kWh savings that accrue from EEMs following an adjustment in base rates.

The Lost Revenue Recovery Adjustment may be positive or negative. A negative Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are less than those estimated in setting base rates. A positive Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are greater than those estimated for the test year in setting base rates. The LRRA for each year subsequent to the test year will incorporate incremental kWh savings reported by the Energy Trust of Oregon for that year.

For the purposes of this Schedule, the Lost Revenue Recovery Adjustment is the product of: (1) the reduction in kWh sales resulting from ETO-reported EEMs plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, and (2) the weighted average of applicable retail base rates (the Lost Revenue Rate). Applicable base rates for Nonresidential Customers are defined as the schedule-weighted average of transmission, distribution, and fixed generation charges; including those contained in Schedule122 and other applicable schedules. System usage or distribution charges will be adjusted to include only the recovery of Trojan Decommissioning expenses and the Customer Impact Offset. Franchise fee recovery is not included in the Lost Revenue Rate. The applicable Lost Revenue Rate is 4.995 cents per kWh.

## SCHEDULE 123 (Continued)

### SNA and LRRA BALANCING ACCOUNTS

The Company will maintain a separate balancing account for the SNA, applicable to Schedules 7, 32 and 532, and 83 and 583 and for the Nonresidential LRRA for the remaining applicable nonresidential Schedules. Each balancing account will record over- and under-collections resulting from differences as determined, respectively, by the SNA and LRRA mechanisms. The accounts will accrue interest at the Commission-authorized Modified Blended Treasury Rate established for deferred accounts.

### DECOUPLING ADJUSTMENT

The Adjustment Rates, applicable for service on and after the effective date of this schedule will be:

| Schedule | Adjustment Rate |
|---|---|
| 7 | (0.052) ¢ per kWh |
| 15 | (0.009) ¢ per kWh |
| 32 | (0.083) ¢ per kWh |
| 38 | (0.009) ¢ per kWh |
| 47 | (0.009) ¢ per kWh |
| 49 | (0.009) ¢ per kWh |
| 75 | |
| Secondary | (0.009) ¢ per kWh |
| Primary | (0.009) ¢ per kWh |
| Subtransmission | (0.009) ¢ per kWh |
| 83 | (0.009) ¢ per kWh |
| 85 | |
| Secondary | (0.009) ¢ per kWh |
| Primary | (0.009) ¢ per kWh |
| 89 | |
| Secondary | (0.009) ¢ per kWh |
| Primary | (0.009) ¢ per kWh |
| Subtransmission | (0.009) ¢ per kWh |

**PORTLAND GENERAL ELECTRIC**
Schedule 83 Hypothetical Decoupling Results

**Schedule 83**

| Month | UE-262 Customers | MWH | kWh per Customer | Volumetric mills/kWh | Charge per Customer | Volumetric Revenues | Customer Revenues | Monthly Delta |
|---|---|---|---|---|---|---|---|---|
| January | 11,074 | 243,673 | 22,004 | 29.73 | $615.72 | $7,244,384 | $6,818,483 | ($425,901) |
| February | 11,078 | 235,781 | 21,284 | 29.73 | $615.72 | $7,009,756 | $6,820,946 | ($188,810) |
| March | 11,083 | 229,392 | 20,698 | 29.73 | $615.72 | $6,819,822 | $6,824,025 | $4,203 |
| April | 11,092 | 218,625 | 19,710 | 29.73 | $615.72 | $6,499,731 | $6,829,566 | $329,835 |
| May | 11,097 | 215,228 | 19,395 | 29.73 | $615.72 | $6,398,716 | $6,832,645 | $433,929 |
| June | 11,102 | 221,066 | 19,912 | 29.73 | $615.72 | $6,572,283 | $6,835,723 | $263,440 |
| July | 11,107 | 231,927 | 20,881 | 29.73 | $615.72 | $6,895,186 | $6,838,802 | ($56,384) |
| August | 11,116 | 244,463 | 21,992 | 29.73 | $615.72 | $7,267,882 | $6,844,344 | ($423,538) |
| September | 11,121 | 242,138 | 21,773 | 29.73 | $615.72 | $7,198,766 | $6,847,422 | ($351,344) |
| October | 11,128 | 226,213 | 20,328 | 29.73 | $615.72 | $6,725,316 | $6,851,732 | $126,416 |
| November | 11,135 | 218,917 | 19,660 | 29.73 | $615.72 | $6,508,413 | $6,856,042 | $347,630 |
| December | 11,140 | 232,710 | 20,890 | 29.73 | $615.72 | $6,918,454 | $6,859,121 | ($59,333) |
| Totals | 133,273 | 2,760,131 | 20,710 | | | $82,058,709 | $82,058,852 | $143 |

**2014 Temperature Adjusted Activity**

| 2014 Month | Actual Customers | WA MWH | kWh per Customer | Volumetric mills/kWh | Charge per Customer | Volumetric Revenues | Customer Revenues | Actuals/forecast | UE 262 Delta | Deferral |
|---|---|---|---|---|---|---|---|---|---|---|
| January | 11,192 | 247,869 | 22,147 | 29.73 | $615.72 | $7,369,157 | $6,891,138 | ($478,018) | ($425,901) | ($52,117) |
| February | 11,205 | 234,561 | 20,934 | 29.73 | $615.72 | $6,973,505 | $6,899,143 | ($74,363) | ($188,810) | $114,447 |
| March | 11,267 | 228,092 | 20,244 | 29.73 | $615.72 | $6,781,162 | $6,937,317 | $156,155 | $4,203 | $151,952 |
| April | 11,274 | 217,960 | 19,333 | 29.73 | $615.72 | $6,479,956 | $6,941,627 | $461,671 | $329,835 | $131,836 |
| May | 11,302 | 219,277 | 19,402 | 29.73 | $615.72 | $6,519,112 | $6,958,867 | $439,756 | $433,929 | $5,827 |
| June | 11,310 | 226,647 | 20,040 | 29.73 | $615.72 | $6,738,218 | $6,963,793 | $225,575 | $263,440 | ($37,865) |
| July | 11,277 | 234,375 | 20,783 | 29.73 | $615.72 | $6,967,961 | $6,943,474 | ($24,486) | ($56,384) | $31,897 |
| August | 11,313 | 248,446 | 21,961 | 29.73 | $615.72 | $7,386,314 | $6,965,640 | ($420,674) | ($423,538) | $2,865 |
| September | 11,335 | 253,956 | 22,405 | 29.73 | $615.72 | $7,550,115 | $6,979,186 | ($570,929) | ($351,344) | ($219,585) |
| October | 11,341 | 223,931 | 19,745 | 29.73 | $615.72 | $6,657,455 | $6,982,881 | $325,426 | $126,416 | $199,010 |
| November | 11,272 | 223,949 | 19,868 | 29.73 | $615.72 | $6,658,013 | $6,940,396 | $282,383 | $347,630 | ($65,246) |
| December | 11,251 | 252,356 | 22,430 | 29.73 | $615.72 | $7,502,554 | $6,927,466 | ($575,089) | ($59,333) | ($515,755) |
| Totals | 135,339 | 2,811,420 | 20,773 | | | $83,583,521 | $83,330,929 | ($252,592) | $143 | ($252,735) |

**PORTLAND GENERAL ELECTRIC**
Schedule 83 Hypothetical Decoupling Results

**Schedule 83**

| Month | UE-283 Customers | MWH | kWh per Customer | Volumetric mills/kWh | Charge per Customer | Volumetric Revenues | Customer Revenues | Monthly Delta |
|---|---|---|---|---|---|---|---|---|
| January | 10,915 | 243,193 | 22,281 | 34.17 | $718.12 | $8,309,899 | $7,838,280 | ($471,619) |
| February | 10,920 | 232,450 | 21,287 | 34.17 | $718.12 | $7,942,809 | $7,841,870 | ($100,938) |
| March | 10,928 | 227,458 | 20,814 | 34.17 | $718.12 | $7,772,249 | $7,847,615 | $75,366 |
| April | 10,936 | 218,122 | 19,945 | 34.17 | $718.12 | $7,453,236 | $7,853,360 | $400,125 |
| May | 10,943 | 213,989 | 19,555 | 34.17 | $718.12 | $7,311,997 | $7,858,387 | $546,391 |
| June | 10,951 | 222,215 | 20,292 | 34.17 | $718.12 | $7,593,081 | $7,864,132 | $271,051 |
| July | 10,958 | 233,941 | 21,349 | 34.17 | $718.12 | $7,993,748 | $7,869,159 | ($124,589) |
| August | 10,966 | 244,730 | 22,317 | 34.17 | $718.12 | $8,362,410 | $7,874,904 | ($487,507) |
| September | 10,973 | 241,934 | 22,048 | 34.17 | $718.12 | $8,266,890 | $7,879,931 | ($386,960) |
| October | 10,981 | 228,510 | 20,810 | 34.17 | $718.12 | $7,808,195 | $7,885,676 | $77,481 |
| November | 10,988 | 218,665 | 19,900 | 34.17 | $718.12 | $7,471,778 | $7,890,703 | $418,924 |
| December | 10,995 | 237,445 | 21,596 | 34.17 | $718.12 | $8,113,507 | $7,895,729 | ($217,778) |
| Totals | 131,454 | 2,762,651 | 21,016 | | | $94,399,799 | $94,399,746 | ($53) |

**2015 Temperature Adjusted Activity**

| 2015 Month | Actual Customers | WA MWH | kWh per Customer | Volumetric mills/kWh | Charge per Customer | Volumetric Revenues | Customer Revenues | Actuals/forecast | UE 283 Delta | Deferral |
|---|---|---|---|---|---|---|---|---|---|---|
| January | 11,355 | 249,062 | 21,934 | 34.17 | $718.12 | $8,510,444 | $8,154,253 | ($356,191) | ($471,619) | $115,428 |
| February | 11,251 | 231,930 | 20,614 | 34.17 | $718.12 | $7,925,048 | $8,079,568 | $154,520 | ($100,938) | $255,459 |
| March | 11,226 | 225,930 | 20,126 | 34.17 | $718.12 | $7,720,045 | $8,061,615 | $341,570 | $75,366 | $266,205 |
| April | 11,201 | 220,539 | 19,689 | 34.17 | $718.12 | $7,535,811 | $8,043,662 | $507,851 | $400,125 | $107,726 |
| May | 11,194 | 221,845 | 19,818 | 34.17 | $718.12 | $7,580,442 | $8,038,635 | $458,193 | $546,391 | ($88,197) |
| June | 11,220 | 234,555 | 20,905 | 34.17 | $718.12 | $8,014,761 | $8,057,306 | $42,546 | $271,051 | ($228,505) |
| July | 11,308 | 251,362 | 22,229 | 34.17 | $718.12 | $8,589,036 | $8,120,501 | ($468,535) | ($124,589) | ($343,946) |
| August | 11,391 | 255,754 | 22,452 | 34.17 | $718.12 | $8,739,120 | $8,180,105 | ($559,015) | ($487,507) | ($71,508) |
| September | 11,411 | 252,523 | 22,130 | 34.17 | $718.12 | $8,628,699 | $8,194,467 | ($434,232) | ($386,960) | ($47,272) |
| October | 11,426 | 228,081 | 19,962 | 34.17 | $718.12 | $7,793,520 | $8,205,239 | $411,719 | $77,481 | $334,238 |
| November | 11,420 | 228,392 | 19,999 | 34.17 | $718.12 | $7,804,158 | $8,200,930 | $396,773 | $418,924 | ($22,151) |
| December | 11,423 | 254,149 | 22,249 | 34.17 | $718.12 | $8,684,260 | $8,203,085 | ($481,176) | ($217,778) | ($263,398) |
| Totals | 135,826 | 2,854,122 | 21,013 | | | $97,525,344 | $97,539,367 | $14,024 | ($53) | $14,076 |