Payson Power

Electric Impact Fee Analysis

April 2024

Corporate location:
Utility Financial Solutions, LLC
185 Sun Meadow Court
Holland, MI USA 49424
(616) 393-9722
Fax (888) 566-4430

Submitted Respectfully by:
Mark Beauchamp, CPA, CMA, MBA
President, Utility Financial Solutions, LLC
mbeauchamp@ufsweb.com
(616) 393-9722

April 2024

David Tuckett
City Manager
Payson Power
439 W. Utah Ave.
Payson, UT 84651

Dear Mr. Tuckett:

We are pleased to present a final report for the Impact Fee Analysis for Payson Power (Payson). This report was prepared to provide Payson with a comprehensive examination of its existing impact fee structure by an outside party.

The specific purposes of this rate study are:

- Identify the fixed cost contributions to plant a new customer provides through electric rate tariffs
- Identify gross investment in plant necessary to service new growth at various sizes and voltages
- Determine impact fees by subtracting the present value of the fixed cost contributions from the impacts on plant

This report utilizes results of the electric cost of service study, financial projections performed in 2022 and Payson's capital improvement plan.

This report is intended for information and use by the utility and management for the purposes stated above and is not intended to be used by anyone except the specified parties.

Sincerely,

Utility Financial Solutions, LLC
Mark Beauchamp, President
185 Sun Meadow Ct
Holland, MI 49424

TABLE OF CONTENTS

LIST OF TABLES

Introduction

This report identifies the impact fees Payson Power should charge to new customers by identifying the amount new customers contribute to system expansion through rates and subtracting the costs for expansion of the system. The purpose of this analysis is to help ensure:

- New customers are not subsidizing existing customers.
- Existing customers are not subsidizing new customers.

This analysis helps to ensure that all customers benefit from growth without being negatively affected by rate increases resulting from system expansion. Growth necessitates additional capacity investments, which often occur intermittently, and cash generated from impact fees is utilized to fund these expansions.

As new customers are integrated into the system, Payson acquires contribution margins from rates to partially cover the fixed infrastructure costs. When the governing body establishes electric rates, they incorporate a recovery component for the replacement cost of existing assets, which new customers contribute to through the rates they are charged. This is commonly referred to as net revenue, which can be allocated to offset a portion of the system expansions.

However, when the costs of system expansion exceed the net revenues generated from customers, it leads to the necessity of impact charges for new customers, as detailed in this report.

Steps to Complete the Analysis

The following steps were taken to complete the impact fee analysis:

1) Identify the contribution margins (Net Revenues) generated by rate tariffs and used to fund replacement cost of existing infrastructure.
2) The contribution margins are valued over an appropriate period to determine the present value of the new customer’s contribution.
3) Evaluate and categorize plant investments into two groups: those designated for future growth and other investments intended for either infrastructure replacement or projects that do not enhance the capacity of the system.
4) Divide the total system cost impacts of new plant investments by residential equivalent factors. This value is then reduced by the value of the contribution margins generated from rates.
5) The residential equivalent factors are converted to amperage and ratioed to each amperage based on the potential capacity needs of each customer.

Step One – Determination of Contribution Margin

Contribution margins were calculated for each class by subtracting variable costs typically power supply costs from revenues to identify the contribution margins generated by each class.

Revenue minus variable cost equals contribution margin

Table 1 identifies the total revenue requirements for each class and subtracts the variable costs to identify the fixed cost recoveries for each class of customers. Expense used in the analysis is from the cost of service study completed in 2023. Variable costs are primarily driven by power supply and transmission costs, and most of the distribution system is classified as fixed cost recovery. This includes distribution and sub-transmission cost recovery used to fund operation, maintenance, replacement, and expansion of the distribution and sub-transmission system. Table 1 below identifies the total recovery of distribution operations for each class.

Table 1 – Contribution Margin by Class

Expense Description	Expense Classification	Residential	Commercial Electric - No Demand	Commercial Electric - Demand	Industrial 1 Electric	Industrial 2 Electric
Power Supply Expenses:						
Summer Demand	Variable	$ 1,607,970	$ 40,668	$ 792,059	$ 228,561	$ 115,202
Summer Energy	Variable	839,730	23,362	477,023	202,439	67,607
Winter Demand	Variable	704,929	22,933	347,403	96,244	58,330
Winter Energy	Variable	1,222,255	46,409	958,082	363,031	156,372
Inter 2 Demand	Variable	310,171	14,038	251,057	57,141	36,804
Inter 2 Energy	Variable	406,805	14,237	336,114	120,812	47,222
Inter 4 Demand	Variable	393,084	19,422	450,682	140,701	86,196
Inter 4 Energy	Variable	641,918	26,431	603,249	245,603	105,539
Distribution Expenses:						
Distribution	Fixed	602,824	18,472	356,329	102,824	53,249
Transmission	Fixed	338,511	10,373	200,094	57,740	29,902
Transformer	Fixed	102,788	3,150	60,758	17,533	9,080
Substation	Fixed	773,561	23,704	457,252	131,947	68,331
Customer Related Expenses:						
Distribution Customer Costs	Variable	269,855	14,560	66,259	(1,313)	(280)
Transformer Customer Costs	Variable	81,144	2,147	4,234	24	24
Substation Customer Costs	Variable	128,972	6,825	33,651	379	379
Meter O&M	Variable	191,395	9,700	24,594	183	183
Meter Reading	Variable	115,332	6,103	30,092	170	170
Billing	Variable	115,329	6,103	30,091	170	170
Services	Fixed	296,731	13,880	104,431	14,585	7,858
Customer Service	Fixed	253,797	13,430	66,219	746	746
Total		$ 9,397,103	$ 335,946	$ 5,649,675	$ 1,779,520	$ 843,081
Total Fixed		$ 1,779,770	$ 62,052	$ 789,316	$ 146,206	$ 96,866

Step Two - Contribution Margin Unit Conversion

The contribution to margin (Net Revenue) is present valued over a specified time period to determine the maximum value a new customer will generate over an appropriate recovery period. Table 2 shows the average net revenue generated by each customer type on a per kWh or kW basis. For example, each kWh sold to the residential class generated $0.0301 cents of fixed cost recovery used to fund the distribution system.

Table 2 – Determination of Present Value of Contribution Margins

Customer Class	Recovery Period (Years)	1	2	3	4	5	6	7
Residential	7	$ 0.0301	$ 0.0301	$ 0.0301	$ 0.0301	$ 0.0301	$ 0.0301	$ 0.0301
Commercial Electric - No Demand	5	0.0295	0.0295	0.0295	0.0295	0.0295	-	-
Commercial Electric - Demand	5	6.13	6.13	6.13	6.13	6.13	-	-
Industrial 1 Electric	5	4.26	4.26	4.26	4.26	4.26	-	-
Industrial 2 Electric	5	4.76	4.76	4.76	4.76	4.76	-	-

Table 3 details the value of the contribution margins by customer class. The value of the fixed cost recovery for a typical residential customer is $1,460.

Table 3 – Average Contribution Margin per Billing Basis

Customer Class	COS Revenue Requirement	Fixed Costs Contribution	Average Contribution per Customer	Recovery Period (Years)	Maximum Utility Investment per Customer
Residential	$ 9,985,546	$ 1,779,770	$ 262	7	$ 1,460
Commercial Electric - No Demand	356,902	62,052	345	5	1,452
Commercial Electric - Demand	6,105,443	789,316	2,223	5	9,366
Industrial 1 Electric	1,958,690	146,206	73,103	5	307,936
Industrial 2 Electric	915,380	96,866	48,433	5	204,018

Step Three - Infrastructure Cost Analysis

The determination of impact fees depends on the additional capacity needed to service new load and is expressed by amperage and voltage requirements.

The infrastructure costs are broken down into the following components:

- Distribution Local – Investments made to service customers peak demands
- Distribution Substation – Investments made to service peaks of customers located in specific areas
- System Substations – Investments made to handle Payson's peak demands
- Transmission System – Investments made to handle Payson's peak demands

Payson provided a capacity plan for the total system with a breakout of the amount attributed to expansion due to growth. The table below outlines the projected Payson investments in plant, the additional capacity provided by the investments, the expansion costs on a per kW basis, and the location of the capacity investment.

In addition, Payson provided historic record of impact fee related revenue and expenditures since the 2022 study. To accurately reflect revenue related to outstanding projects, UFS allocated the net fund balance at Year End 2023 to the components below.

Table 4 is used to identify the cost impacts associated with each type of cost component.

Table 4 – Cost of Additional Investment in Plant

Capital Projects	Impact Related %	Start Date	Bonding - Impact only	Bonded	Bonding Years	Bonding Interest	Total to be Spent (net of past spending)	Impact Fee Cost
New Power Resource	56%	2024	$ 18,513,000	Yes	20	5.0%	$ 33,000,000	**$ 18,513,000**
SUVPS Bond Payment-Impact Fee	50%	2024 - 2033	3,840,000	Yes	25	5.0%	7,680,000	**3,840,000**
South Substation, T-line, Feeders	83%	2024	6,970,128	Yes	20	5.0%	8,367,500	**6,970,128**
North/Arrowhead Substation, T-line, Feeders	73%	2025	4,581,470	Yes	20	5.0%	6,250,300	**4,581,470**
Strong Tie Feeders 510 - 730	53%	2025	-	No			205,300	**107,783**
Feeder 510/610 I-15 Crossing	45%	2024	-	No			74,400	**33,406**
South Substation tie to 800 South SR-198/500W	44%	2024	-	No			244,100	**107,648**
Strong Tie Feeders 710 - 320	49%	2024	-	No			368,500	**180,197**
46 kV T-loop to South Substation	29%	2025	-	No			2,448,700	**697,880**
South Substation 810 tie to 510/730	41%	2024	-	No			628,000	**257,480**
Rebuild 330 Mainline	42%	2027	-	No			369,900	**153,509**
Strong Tie Feeders Arrowhead 920 - 330	48%	2029	-	No			496,600	**238,368**
510 Mainline	55%	2027	-	No			355,800	**194,978**
730 Mainline	28%	2027	-	No			612,500	**170,275**
Southwest Substation and Feeders	30%	2029	2,311,768	Yes	20	5.0%	7,604,500	**2,311,768**
North Substation and Feeders	30%	2029	2,311,768	Yes	20	5.0%	7,604,500	**2,311,768**
Total							**$ 76,967,200**	**$ 41,029,257**

Step Four – Determine Cost Impact per Residential Equivalent Unit

Payson's base installation for a residential home is 100 AMP 120/240 volt service. To determine the impact fee, UFS conducts the following steps.

1. Determine growth in kWh sales due to impact fee related projects
2. Convert growth to a residential equivalent unit (REU) based on average residential monthly use
3. Divide the adjusted impact fee investment by the REU to determine average cost
4. Subtract the maximum utility contribution to determine the impact fees to be recovered per REU

Table 5 – Calculation of Impact Fees by REU

Capital Projects	Start Date	Bonding - Impact only	2024	2025	2026	2027	2028	2029	Six Year Total
New Power Resource	2024	$ 18,513,000	$ 1,485,531	$ 1,485,531	$ 1,485,531	$ 1,485,531	$ 1,485,531	$ 1,485,531	$ 8,913,186
SUVPS Bond Payment-Impact Fee	2024 - 2033	3,840,000	272,457	272,457	272,457	272,457	272,457	272,457	1,634,745
South Substation, T-line, Feeders	2024	6,970,128	559,301	559,301	559,301	559,301	559,301	559,301	3,355,806
North/Arrowhead Substation, T-line, Feeders	2025	4,581,470	367,629	367,629	367,629	367,629	367,629	367,629	2,205,774
Strong Tie Feeders 510 - 730	2025	-	-	107,783	-	-	-	-	107,783
Feeder 510/610 I-15 Crossing	2024	-	33,406	-	-	-	-	-	33,406
South Substation tie to 800 South SR-198/500W	2024	-	107,648	-	-	-	-	-	107,648
Strong Tie Feeders 710 - 320	2024	-	180,197	-	-	-	-	-	180,197
46 kV T-loop to South Substation	2025	-	-	697,880	-	-	-	-	697,880
South Substation 810 tie to 510/730	2024	-	257,480	-	-	-	-	-	257,480
Rebuild 330 Mainline	2027	-	-	-	-	153,509	-	-	153,509
Strong Tie Feeders Arrowhead 920 - 330	2029	-	-	-	-	-	-	238,368	238,368
510 Mainline	2027	-	-	-	-	194,978	-	-	194,978
730 Mainline	2027	-	-	-	-	170,275	-	-	170,275
Southwest Substation and Feeders	2029	2,311,768	185,502	185,502	185,502	185,502	185,502	185,502	1,113,013
North Substation and Feeders	2029	2,311,768	185,502	185,502	185,502	185,502	185,502	185,502	1,113,013
Total			$ 3,634,653	$ 3,861,585	$ 3,055,923	$ 3,574,685	$ 3,055,923	$ 3,294,291	$ 20,477,060
Less Current Impact Fee Balance									$ (1,592,226)
Net Impact Fee Recovery									**$ 18,884,834**

Determination of Residential Equivalent Units		Base Impact Fee - 200 Watt
Actual kWh Purchases 2023		140,719,395
Projected kWh Purchases 2028		168,827,225
Change in Purchases adjusted for losses		27,105,388
Average Residential kWh annual use		8,692
Residential Equivalent Units		**3,118**
Total Investment	$	18,884,834
Average cost per Residential Equivalent	$	6,056
Less Maximum Utility Contribution		1,460
Impact Fees to be recovered per Residential Equivalent	**$**	**4,596**

Therefore, a 200 AMP 120/240 volt service requires $4,596 to be recovered through impact fees.

Step Five – Conversion to Amperage

Table 6 expresses the Table 5 results by amperage and voltage level using a typical residential customer’s 200 AMP service voltage as the base.

Table 6 – Impact Fees by Amperage and Voltage Level

	120/240 Volt	120/208 Volt	277/480 Volt
AMPS	Impact Fee	Impact Fee	Impact Fee
10	$ 230	$ 345	$ 796
20	460	690	1,592
30	689	1,035	2,388
40	919	1,380	3,184
50	1,149	1,725	3,980
60	1,379	2,070	4,776
70	1,609	2,414	5,572
80	1,838	2,759	6,368
90	2,068	3,104	7,164
100	2,298	3,449	7,960
125	2,872	4,312	9,950
150	3,447	5,174	11,940
175	4,021	6,036	13,930
200	4,596	6,899	15,920
300	6,894	10,348	23,880
400	9,192	13,797	31,840
500	11,489	17,246	39,799
600	13,787	20,696	47,759
700	16,085	24,145	55,719
800	18,383	27,594	63,679
900	20,681	31,044	71,639
1000	22,979	34,493	79,599
1100	25,277	37,942	87,559
1200	27,575	41,391	95,519
1300	29,873	44,841	103,478
1400	32,170	48,290	111,438
1500	34,468	51,739	119,398
1600	36,766	55,189	127,358
1700	39,064	58,638	135,318
1800	41,362	62,087	143,278
1900	43,660	65,536	151,238
2000	45,958	68,986	159,198
2500	57,447	86,232	198,997
3000	68,937	103,478	238,796

Significant Assumptions

The following assumptions are made in the creation of this report:

1) **Discount Rate** – 6.0%
2) **Recovery Period:**
   All Residential Services – 7 year recovery
   Commercial and Industrial – 5 year recovery

Statistical Information

Table 7 – Class Load Data and Statistics

Statistics are from the base year for the cost of service study for July 2021 – June 2022.

Description	Residential	Commercial Electric - No Demand	Commercial Electric - Demand	Industrial 1 Electric	Industrial 2 Electric
Number of Customers	6,803	180	355	2	2
Energy at Meter	59,134,908	2,105,957	45,801,857	18,005,509	7,265,562
NCP Meter	17,863	560	10,559	3,047	1,639
NCP Primary	18,709	581	11,059	3,191	1,688
NCP Input	19,586	600	11,577	3,341	1,730
Average Load Factor	19%	16%	16%	24%	16%
Group Diversity Factor	100%	100%	85%	85%	91%
Monthly Distribution Max NCP	36,003	1,510	32,212	8,520	5,138

Considerations

Currently, some new customers are not contributing enough to cover the cost of capacity upgrades to the system, while others are over contributing. The tables below compare the current and proposed impact fees. However, UFS proposes to charge impact fees based on the voltage and amperage of service outlined in Table 6.

Table 8 – 120/240 Voltage Current vs. Proposed Fees

Residential Single Phase (120/240V)						
Amps	kVA	Max Capacity (kW)	Average Use (kW)	Current Fee	Proposed Fee	% Change
60	14.4	2.00	1.20	$ 739	$ 1,379	87%
100	24	5.00	2.00	$ 1,263	$ 2,298	82%
125	30	6.00	2.40	$ 1,515	$ 2,872	90%
150	36	7.00	2.80	$ 1,768	$ 3,447	95%
200	48	8.00	3.20	$ 2,021	$ 4,596	127%
225	54	10.00	4.00	$ 2,526	$ 3,550	41%
400	96	14.00	5.60	$ 3,536	$ 9,192	160%
Commercial (120/240V)						
Amps	**kVA**	**Max Capacity**	**Average Use**	**Current**	**Proposed**	**% Change**
100	24	5.00	2.25	$ 1,421	$ 2,298	62%
125	30	7.00	3.15	$ 1,989	$ 2,872	44%
150	36	9.00	4.05	$ 2,557	$ 3,447	35%
200	48	14.00	6.30	$ 3,978	$ 4,596	16%
400	96	19.00	8.55	$ 5,399	$ 9,192	70%

Table 9 – 120/208 Voltage Current vs. Proposed Fees

Commercial 3 Phase (120/208V)						
Amps	kVA	Max Capacity	Average Use	Current	Proposed	% Change
125	45	16.00	7.00	$ 4,546	$ 4,312	-5%
150	54	24.00	11.00	$ 6,819	$ 5,174	-24%
200	72	31.00	14.00	$ 8,808	$ 6,899	-22%
400	144	63.00	28.00	$ 17,900	$ 13,797	-23%
600	216	94.00	42.00	$ 26,709	$ 20,696	-23%
800	288	126.00	57.00	$ 35,801	$ 27,594	-23%
1,000	360	157.00	71.00	$ 44,609	$ 34,493	-23%
1,200	432	189.00	85.00	$ 53,701	$ 41,391	-23%
1,600	576	252.00	113.00	$ 71,602	$ 55,189	-23%
2,000	720	315.00	142.00	$ 89,502	$ 68,986	-23%

Table 10 – 277/480 Voltage Current vs. Proposed Fees

Commercial 3 Phase (277/480V)						
Amps	kVA	Max Capacity	Average Use	Current	Proposed	% Change
125	104	35	16	$ 9,945	$ 9,950	0%
150	125	52	23	$ 14,775	$ 11,940	-19%
200	166	73	33	$ 20,742	$ 15,920	-23%
400	332	145	65	$ 41,199	$ 31,840	-23%

Proposed Rate Design

Table 11 – Proposed Impact Fees by Amperage and Voltage

120/240 Volt		120/208 Volt	277/480 Volt
AMPS	Impact Fee	Impact Fee	Impact Fee
10	$ 230	$ 345	$ 796
20	460	690	1,592
30	689	1,035	2,388
40	919	1,380	3,184
50	1,149	1,725	3,980
60	1,379	2,070	4,776
70	1,609	2,414	5,572
80	1,838	2,759	6,368
90	2,068	3,104	7,164
100	2,298	3,449	7,960
125	2,872	4,312	9,950
150	3,447	5,174	11,940
175	4,021	6,036	13,930
200	4,596	6,899	15,920
300	6,894	10,348	23,880
400	9,192	13,797	31,840
500	11,489	17,246	39,799
600	13,787	20,696	47,759
700	16,085	24,145	55,719
800	18,383	27,594	63,679
900	20,681	31,044	71,639
1000	22,979	34,493	79,599
1100	25,277	37,942	87,559
1200	27,575	41,391	95,519
1300	29,873	44,841	103,478
1400	32,170	48,290	111,438
1500	34,468	51,739	119,398
1600	36,766	55,189	127,358
1700	39,064	58,638	135,318
1800	41,362	62,087	143,278
1900	43,660	65,536	151,238
2000	45,958	68,986	159,198
2500	57,447	86,232	198,997
3000	68,937	103,478	238,796