REQUEST FOR PROPOSAL – RFP #2012-05

SPRINGVILLE CITY ELECTRICAL CAPITAL FACILITIES PLAN, IMPACT FEE FACILITIES PLAN, AND IMPACT FEE STUDY

1. NOTICE TO PROFESIONALS

Springville City (the "City") is located in Utah County, occupies approximately 14.37 square miles in city limits and has approximately 30,000 residents. Springville's Power Department also serves approximately 9.93 square miles in Hobble Creek Canyon. Springville is approximately 50% built-out with a projected population of approximately 60,000 when fully developed. The City last conducted an electrical capital facilities plan ("CFP") and impact fee study in 2004.

This Request for Proposal will assist the City in selecting an experienced consultant or consulting team (the "Consultant") to conduct the activities necessary to update the City's electrical CFP and complete an impact fee facilities plan ("IFFP") and an impact fee analysis ("IFA"). The IFFP and IFA shall satisfy the requirements of the "Impact Fees Act," ***Utah Code Annotated §11-36a-101, et seq.***, as well as all other applicable federal and state laws. After completing the CFP, IFFP, and IFA, the Consultant shall prepare a recommendation for impact fees for the City Council's consideration for its comprehensive long range infrastructure and financial planning efforts.

The City intends to compare and evaluate all eligible submittals and select the most qualified firm(s) or team(s) as outlined in subsection 3.13, "Evaluation Criteria," of this RFP.

2. SCOPE OF WORK

The City is requesting municipal engineering and financial analysis services to update the City's electrical CFP and prepare an electrical IFFP and IFA. The successful firm(s) will be required to attend necessary staff meetings, board meetings, public hearings and City Council meetings to gather information and to present and defend findings. The IFFP will need to address the required 6-year planning window for the impact fee calculations and 10 and 20 year planning window for facilities planning. The IFFP and its corresponding IFA shall be prepared in strict accordance with ***Utah Code Annotated §11-36a-101, et seq*.** Each proposal shall include all work, services, and expenses necessary to update the electrical CFP and complete CFP, IFFP, and IFA and shall include at a minimum the following:

Capital Facilities Plan Update:

- Analysis of existing City population and projected growth from present to build out.

- Identification of existing infrastructure and delineation of associated service areas.
- Calculation of current level of service for the utility system.
- Identification of system deficiencies or surpluses for the utility system.
- Projected asset replacement schedule and projects for the utility system.
- Analysis of the demands placed upon existing facilities by new development activity.
- Identification of Capital Improvement Projects ("CIP") necessary to accommodate projected development within the service area for the utility system.
- Categorization of identified CIP into impact fee vs. non-impact fee eligible projects including a list of potential funding sources for each project.
- Cost estimates for each CIP inclusive of land/easement acquisition, construction, and planning/surveying/engineering costs.
- Recommended construction schedule for each CIP based on prioritization of CIPs, including, but not limited to 6, 10 and 20-year plans.
- Identification and quantification of all revenue sources, including impact and user fees, available to finance proposed CIPs.
- Recommendations on utility fee structures to address system deficiencies and maintain utility infrastructure.
- Recommendations on expected staffing requirements to expected growth and expanded facilities.
- Solicit and document input from all stake holders and affected entities during the CFP process.
- Evaluate the condition of the City's transmission network, distribution network, substations, N-1 contingencies.
- Review the condition of all the City's substations.
- Review and include Southern Utah Valley Power System's capital improvement projects as they relate to growth in the impact fee calculation.

(The City's current CFP is attached as Exhibit "A.")

Impact Fee Facilities Plans:

- Identify demands placed on existing facilities by new development activities.
- Identify and propose means whereby the City will meet those demands.
- Identify any public facilities required for a planned school district or charter school facility.
- Identify and consider all revenue sources including impact fees and anticipated dedication of system improvements to finance the impacts on system improvements.
- Identify the public facilities required to serve development resulting from new development activity.
- Calculate the costs of needed improvements including:
    - Construction contract price,
    - Costs for land acquisition, improvements, materials, fixtures,
    - Costs for planning, surveying, engineering fees for services directly related to the construction of the system improvements, and

    - Debt Service Charges.
- Analysis of the City's plan for financing system improvements to ensure that any impact fees imposed are necessary to achieve an equitable allocation of the costs borne in the past and to be borne in the future, in comparison to the benefits already received and yet to be received.
- Identify overhead costs consistent with generally accepted accounting principles and methodological standards set by the Office of Management and Budget for federal grant reimbursement.
- Insure that all cost estimates are based on realistic estimates and assumptions that shall be disclosed in the IFA.
- Identify and value excess capacity at actual cost.
- Solicit and document input from all stake holders and affected entities during the IFFP process.
- Include any other requirements for an IFFP contained in the "Impact Fees Act," ***Utah Code Annotated §11-36a-101, et seq.***

Impact Fee Analysis:

- Identify anticipated impact on, or consumption of, any existing capacity of a public facility by the anticipated development activity.
- Identify the anticipated impact on system improvements required by the anticipated development activity to maintain the established level of service for each public facility.
- Working with the Power Superintendent and Director, define the existing level of service for each area under this study.
- Identify how the anticipated impacts are reasonably related to the anticipated development activity.
- Estimate the proportionate share of the costs for existing capacity that will be recouped and how the cost of impact in system improvements is reasonably related to new development.
- Identify and communicate in the study how the impact fees are calculated.
- Identify and analyze whether or not the proportionate share of the costs of public facilities are reasonably related to the new development activity.
- Identify the cost of each existing facility that has excess capacity to serve anticipated development resulting from new development activity.
- Identify the cost of system improvements for each public facility.
- Identify other than impact fees the manner of financing each public facility (user charges, special assessments, general taxes etc.)
- Identify the relative extent to which development activity will contribute to the cost of existing public facilities and system improvements in the future.
- Identify the extent to which development activity is entitled to a credit against impact fees because the development activity will dedicate system improvements of public facilities that will offset the demand for system improvements, inside or outside the proposed development.
- Identify extraordinary costs, if any, in servicing newly developed properties.

- Identify the time-price differential inherent in fair comparisons of amounts paid at different times.
- Prepare summary of Impact Fee Analysis designed to be understood by a lay person.
- Include any other requirement for an impact fee analysis contained in the "Impact Fees Act," ***Utah Code Annotated §11-36a-101, et seq.***

The successful firm or team shall manage the implementation of the entire impact fee process including all public notices and any documentation necessary to adopt the CFP, IFFP, and IFA according to State Code. The successful firm shall complete the required Impact Fee Certification for both the IFFP and IFA consistent with ***Utah Code Annotated §11-36a-306(1) (2).***

3. INSTRUCTIONS TO PROPOSERS

3.1 PROJECT TIMETABLE

The following timetable has been established for this project. *LATE PROPOSALS WILL NOT BE ACCEPTED.*

- **Closing Date for Receipt of Proposals August 16, 2012 @ 2:00 p.m.**
- **Awarding of Bid September 4, 2012 (projected).**
- **Commencement of Work September 10, 2012 (projected).**
- **CFP, IFFP, IFA complete no later than March 15, 2013.**

3.2 PROPOSALS EVALUATION

The procedure for response to this RFP, evaluation of proposals, and selection of a Consultant is as follows:

A. Interested entities will prepare and submit their proposals according to the Project timetable contained in Subsection 3.1
B. The City and/or its representatives will evaluate all submitted proposals in accordance with the evaluation criteria as outlined in Subsection 3.13.
C. A contract incorporating the provisions, terms and conditions of this RFP will be executed between the City and the selected Consultant.

3.3 PROPOSAL SUBMISSION

Each respondent must submit *THREE (3) COPIES* of its *SEALED* proposal to the City. The envelope containing the proposal must be clearly labeled "SEALED PROPOSAL – SPRINGVILLE CITY ELECTRIAL CAPITAL FACILITIES AND IMPACT FEE FACILITIES PLANS, RFP #2012-05." The proposals must be delivered to:

Bruce Riddle

Finance Director
110 South Main
Springville, UT 84663

3.4 PROPOSAL ORGANIZATION AND CONTENT

All requested documentation must be included. The proposal must include (in the following order):

A. Cover Letter. The letter must state the respondent's intent to participate in the contract. The letter shall be on official business letterhead and shall include the following:

1. A statement that the respondent will comply with all terms and conditions as indicated in the RFP.
2. A statement indicating whether the respondent is a corporation or other legal entity.
3. A statement of affirmative action that the respondent does not discriminate in its employment practices with regard to race, color, religion, age (except as provided by law), sex, marital status, political affiliation, national origin, or handicap.
4. A certification statement to the effect that the person signing the proposal is authorized to sign on behalf of the respondent.
5. Names of the key contact persons with their title and telephone numbers. Also, indicate first and second back-up contact persons if the person signing the proposal is not available to take a call from the City.
6. Name and complete mailing address of the respondent along with telephone number and fax number.

B. Comprehensive RFP Response. The response must include all requested information and documentation. **The proposed price and schedule must be included and shall be inclusive of all costs to complete the work including but not limited to travel, equipment, and reproduction costs**. The proposal response shall include at a minimum the following sections:

1. Executive Summary (three pages maximum) with proposed bid price.
2. Organizational Chart showing the team involved including individual members, all organizations, relationships, and breakdown of responsibilities and the percentage of work that is expected to be performed by each team member. Indicate offices/locations that will provide services along with a percentage of work to be performed at each of these locations.
3. Proposer Qualifications describing the proposer's experience on similar projects, including the individual team members' involvement on the specific projects described. Project information, such as plans for the identified projects should be briefly included. Resumes of principals and other key staff scheduled to participate on the projects should be included. For all major participants, note

the approximate full time equivalent hours to be devoted to the project. Provide a minimum of three references, including name, address and telephone number, of persons who can attest to performance on relevant projects.

4. Work Plan describing the methodology and process proposed to be used to complete the scope of work defined in Section 2, including any potentially innovative or creative solutions for the project. It should address the proposed schedule for the Consultant's work and identify any proposed strategies to be used to keep the project on schedule, control costs, and maximize project effectiveness. The work plan should also identify milestones, describe outputs to be delivered, propose a quality assurance/quality control ("QA/QC") plan, and identify advantages of the proposal to the City.

3.5 ORAL PRESENTATION

As part of the proposal evaluation process, selected proposers may be invited to make oral presentations to the City. These presentations must be made by the same project team personnel who will be assigned to the project should the proposer be awarded a contract.

3.6 SUBMITTAL OWNERSHIP

All proposals (and the information contained therein) shall become the property of the City. Proposers should carefully consider the items submitted before submitting items that would not be disposable to the proposer. Proposals submitted may be reviewed and evaluated by any persons at the discretion of the City. No proposal shall be returned to the respondent regardless of the outcome of the selection process. Cost for developing proposals and making proposal presentations are entirely the responsibility of the proposer and shall not be chargeable in any manner to the City.

3.7 CITY USE OF PROPOSAL IDEAS

The City reserves the right to use any or all ideas presented. Selection or rejection of the proposal does not affect this right.

3.8 QUESTIONS AND CLARIFICATIONS

Questions regarding this RFP should be directed to:

Brandon Graham, Springville Power Superintendent
E-Mail: bgraham@springville.org
Telephone: 801-489-2750

3.9 ACCEPTANCE OF PROPOSAL

A. The City reserves the right to reject any or all proposals for any reason and/or waive minor irregularities when to do so would be in the best interests of the City.

Minor irregularities are those which will not have a significant adverse effect on overall competition or performance levels.

B. The responding party agrees that the City may terminate this procurement procedure at any time and for any reason, and the City shall have no liability or responsibility to the responding party for any costs or expenses incurred in connection with this RFP, or such party's response.

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3.10 DISQUALIFICATION OF PROPOSAL

A. The City reserves the right to reject any and all proposals received by reason of this RFP, or to negotiate separately with any source whatsoever in any manner necessary to serve the best interests of the City.

B. The occurrence of any of the following may result in disqualification of a proposal:

1. Failure to respond by the established submission deadline.
2. Failure to completely answer all questions posed in the RFP.
3. Use of any other type of form or format other than those indicated in the RFP.
4. Failure to provide requested documentation at the time of proposal submission.
5. Illegible responses.
6. If the proposer adds any provisions reserving the right to accept or reject an award or to enter into a contract pursuant to an award, or any other unauthorized conditions, limitations or provisions.
7. If the proposer is unable to evidence a satisfactory record of integrity.
8. If the proposer is not qualified legally to contract.
9. Any unauthorized contact with any city staff.

3.11 WITHDRAWAL OF PROPOSAL

The proposal may be withdrawn upon request by the proposer, without prejudice, prior to, but not after, the time fixed to receive proposals.

3.12 EVALUATION CRITERIA

A. All requirements identified in this RFP must be satisfied to ensure that the proposal will qualify for consideration. The City desires to receive proposals from firms who can demonstrate operational and technical qualifications and capabilities.

B. All proposals will be evaluated by representatives of the City to identify the proposal that best meets the needs of the City as set forth in the RFP. In evaluating the proposals, City representatives will base their evaluations on the following components:

1. <u>Qualifications</u>: This category represents an evaluation of the Consultant's understanding of the project and the technical approach to be used to meet the City's needs for completing the CFP, IFFP, and IFA. (15%)

2. Key Personnel and Project Teams: This category deals with the experience level of key personnel proposed for this project and the proposer's willingness and demonstrated ability to work effectively with the City. Experience relates to the overall assessment of the proposer's assigned personnel. Evaluation will be based on resumes that are provided, direct contact with identified current and previous clients, submitted information in response to the RFP, and the oral interviews. (20%)
3. Project Approach: This category represents an evaluation of the Consultant's plan for managing the project, QA/QC plan, and previous experience with this type of project. This category will also evaluate the Consultant's proposed schedule and work plan to insure completion by the requested date. (20%)
4. Project and Client Experience: This category deals with the proposer's performance on similar prior projects and the proposer's willingness and demonstrated ability to work effectively with the City. Experience relates to the overall assessment of the proposer's assigned personnel. Evaluation will be based on resumes that are provided, direct contact with identified current and previous clients, submitted information in response to the RFP, and the oral interviews. (20%)
5. Fee Proposal: This category will evaluate the Consultant's proposed fees. (25%)

Non-responsive proposals (those not conforming to the RFP requirements) will be automatically eliminated from the evaluation process.

3.13 NON-COLLUSION

Consultant shall guarantee that the proposal submitted is not a product of collusion with any other bidder and no effort has been made to fix the proposal price of any bidder or to fix any overhead, profit, or cost estimate of any proposal or its price.

3.14 RFP CLARIFICATIONS

Should the RFP not contain sufficient information in order for the firm to obtain a clear understanding of the services required by the City, or should it appear that the instructions outlined in the RFP are not clear or contradictory, the Consultant may obtain written clarification from the City at least 24 hours prior to the required time and date for proposal submission. The Consultant shall include a copy of the written clarification with its submission.

3.15 AMENDMENTS

No oral modifications or amendments to this RFP shall be effective. If it becomes necessary to revise any part of the RFP, an addendum will be provided to all who received an RFP.

4. GENERAL REQUIREMENTS

The Consultant who is awarded the bid under this RFP shall be required to meet all of the conditions of this RFP, including the general requirements in this Section 4. The term “Contract” as used in this RFP shall mean the Contract that is entered into between the Consultant, who is awarded the bid, and the City.

4.1 EMPLOYMENT STATUS VERIFICATION

The Consultant shall register and fully comply with the Private Employer Verification Act, Utah Code Annotated §13-47-101, et seq. Consultant shall, by contract, require its Consultants, subcontractors, contract employees, staffing agencies, or any Consultants (regardless of their tier) to register and fully comply with the Private Employer Verification Act, Utah Code Annotated §13-47-101, et seq.

The Consultant shall also agree to abide by the Federal and State regulations pertaining to Equal Opportunity Employment that requires project participants not to discriminate against any employee or applicant for employment because of race, color, religion, sex, age, disability, or national origin. The City will make every effort to ensure all bidders are treated fairly and equally throughout the entire advertisement, review, and selection process.

4.2 PAYMENTS

The City shall make payment to the Consultant for all services performed by the Consultant pursuant to the Contract. The Consultant shall submit a written invoice, for services rendered and City shall pay the invoice fee within thirty (30) days, as long as all Contract requirements are met. A five percent (5%) retainage will be withheld until final product is reviewed and accepted by the City. Invoices shall be submitted to:

Springville City
Attn: Brandon Graham
110 North Main Street
Springville, Utah, 84663

4.3 PAYMENT WITHHELD

The City may withhold or, on account of subsequently discovered evidence, nullify the whole or part of any invoice to such extent as may be necessary to protect itself from loss on account of:

A. Defective study not remedied.
B. Claims filed or reasonable evidence indicating probable filing of claims.
C. Any other violation of or failure to comply with the provisions of this contract.

When the above issues for withholding payment are resolved, payment shall be made for amounts withheld. The City reserves the right, in case of the Consultant default, to procure the services from other sources while holding the defaulting Consultant responsible for any excess costs occasioned thereby.

4.4 ACCEPTANCE AND FINAL PAYMENT

In a timely manner after the study has been delivered and accepted, the City will make a final determination that the Contract has been completed and that the study has been accepted by the City under the terms and conditions thereof, with qualifications, if any, as stated and the balance found to be due the Consultant according to the terms of payment shall be paid by the City, as provided for making payments under this document.

4.5 RECORD KEEPING AND AUDIT RIGHTS

The Consultant shall maintain accurate accounting records for all goods and services provided under the Contract and shall retain all such records for a period of at least three (3) years following termination of the Contract. Upon 48-hour notice and during normal business hours, the City, or any of its duly authorized representatives, shall have access to and the right to audit any records or other documents pertaining to the Contract. The City's audit rights shall extend throughout the term of the Contract and for a period of at least three (3) years thereafter.

4.6 MANAGEMENT REPORTS

Upon request the Consultant should be able to summarize and concisely report pertinent information to City in a timely manner, throughout the duration of the Contract
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4.7 RIGHT OF THE CITY TO TERMINATE CONTRACT

The City, upon written notice, may terminate the Contract, or any part thereof, as a result of the Consultant’s failure to render to the satisfaction of the city, the material, work and/or services required of it, including progress of the work and such abandonment or termination shall not be deemed a breach by the City. The City shall be the sole determinant in all termination for cause issues. The Consultant shall not be entitled, nor shall the City give any consideration to claims for any costs or for loss of anticipated revenue(s), including overhead and profit, due to the abandonment or termination of the Contract, or any part hereof, by the City for cause.

The City, upon written notice, may abandon or terminate the Contract, or any part thereof, and such action shall in no event be deemed a breach of the Contract. Such termination may come about for the sole convenience of the City. Upon receipt of written notification from the City that the Contract, or any part thereof, is to be terminated, the Consultant shall immediately cease operation of the work stipulated, and assemble all material that has been prepared, developed, furnished or obtained under the provisions of the Contract that may be in its possession or custody, and shall transmit the same to the City on or before the fifteenth day following the receipt of the above-written notice of termination, together with its evaluation of the cost of the work performed. The Consultant shall be entitled to just and equitable payment in accordance with the Contract for any uncompensated work satisfactorily performed prior to such notice.

The City shall determine the amount of work satisfactorily performed by the Consultant and the City's evaluation shall be used as a basis to determine the amount of compensation due the Consultant for this work.

Termination by the City for cause, default, or negligence on the part of the Consultant shall be excluded from the foregoing provision; termination costs shall not apply.

4.8 INDEMNIFICATION

The Consultant at its own expense, agrees to protect, indemnify, pay on behalf of, defend (with counsel acceptable to the City) and hold harmless the City, its elected and appointed officials, employees and volunteers and their agents from all claims, demands, judgments, expenses, and all other damages of every kind and nature, made, rendered, or incurred by or in behalf of any person or persons whomsoever, including the parties hereto and their employees, which may arise out of any act or failure to act, work or other activity related in any way to this project under the Contract by the Consultant, Consultant's agents, employees, subcontractors, or suppliers in the performance and execution of the Contract.

4.9 INSURANCE

The Consultant shall provide the following minimum insurance coverage from companies holding a General Rating of "A" or better as set forth in the most current issue of Best's Key Rating Insurance Guide written for not less than the following, or greater if required by law and all such insurance to be primary to any insurance maintained by the City:

A. The Consultant's Worker's Compensation Insurance shall be written for not less than the statutory limits for the State of Utah and the Consultant's Employer's Liability Insurance shall be written for not less than $1,000,000.
B. The Consultant's Comprehensive Automobile Liability Insurance shall be written with combined single limits of not less than $1,000,000 each occurrence.
C. The Consultant's professional liability/errors and omissions insurance appropriate to Consultant's profession shall be written with a minimum

coverage of $1,000,000; with neither the Consultant nor listed sub-consultants having less than $500,000 individually. The professional liability/errors and omissions insurance must be project specific with at least a one year extended reporting period, or longer upon request.

D. The Consultant's Comprehensive General Liability Insurance with contractual liability coverage on occurrence form with limits not less than $1,000,000 each occurrence and $2,000,000 aggregate.
E. The Consultant shall likewise require its subcontractors, if any, to provide for such benefits and carry and maintain such insurance at no expense to the City.
F. All insurance coverage furnished under this Contract, with the exception of Worker's Compensation and Employer’s Liability, shall include the City, and its directors, officers, agents, and employees as additional insured with respect to the activities of the Consultant and its subcontractors.
G. The Consultant shall not commence work under the Contract until all of the insurance required herein shall have been obtained by the Consultant. The Consultant shall furnish to the City Certificates of Insurance verifying that such insurance has been obtained. Such certificates will provide that City will receive at least thirty (30) days prior written notice of any material change in,

4.10 MINOR CHANGES IN THE WORK

The City will issue supplemental instructions authorizing minor changes in the work, not involving adjustment to the Contract Sum or the Contract Time.

4.11 PROPOSAL REQUESTS

Consultant-Initiated Proposals: If latent or changed conditions require modifications to the Contract, Consultant may initiate a claim by submitting a request for a change to City that includes the following:

A. A statement outlining reasons for the change and the effect of the change on the work, providing a complete description of the proposed change that indicates the effect of the proposed change on the Contract Sum and the Contract Time.
B. Include a list of quantities of products required or eliminated and unit costs, with total amount of purchases and credits to be made. If requested, furnish survey data to substantiate quantities.
C. Include an updated Consultant's construction schedule that indicates the effect of the change, including, but not limited to, changes in activity duration, start and finish times, and activity relationship. Use available total float before requesting an extension of the Contract Time.
D. Proposal Request Form: Use form acceptable to City.

4.12 CHANGE ORDERS

On City's approval of a work change proposal request, City will issue a Change Order for signatures of the City and Consultant.

4.13 LAWS AND ORDINANCES

The laws of the State of Utah shall govern the Contract. Further, the place of performance and transaction of business shall be deemed to be in the Utah County, Utah, and in the event of litigation, exclusive venue and place of jurisdiction shall be Utah, and more specifically, the district court of Utah County, Utah.

4.14 CONFIDENTIAL MATTERS

All data and information gathered by the Consultant, and all reports, recommendations, documents, and data shall be treated by the Consultant as confidential. The Consultant must agree not to communicate and disclose the aforesaid matters to a third party or use them in advertising, publicity, or propaganda and/or in another job or jobs, unless prior written consent is obtained from City.

4.15 WARRANTY

The Consultant assumes all responsibility for all of the materials and services provided under this Agreement, whether those materials and services are provided by the Consultant, purchased ready-made, or provided by a subcontractor.

Exhibit “A”

SPRINGVILLE CITY POWER

Ten-Year Capital Plan
& Impact Fee Study

May 2004

Submitted by

Electric Power Engineering Associates
Brent Davis, P.E.
John Nelson, P.E.

P.O. Box 50056
Provo, Utah 84605
(801) 375-4634
Fax No. (801) 375-4634

Ten-Year Capital Plan
& Impact Fee Study

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Part A:

Springville City Power

Ten-Year Capital Plan

May 2004

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Continued growth and reliability of the Springville Power System requires a consistent, knowledgeable and diligent commitment to the Capital Improvement and Upgrade of the supply, transmission and distribution resources of the City. Springville is nearing the point of continued load growth exceeding the ability of its power system to reliably provide the service desired and expected and deserved by its citizens. Wise decisions in the past and dedicated, skilled employees have provided the needed support to bring the system to this point, but Springville is no longer a small rural community. It has international businesses and technically capable residents who depend upon reliable electrical service. This report identifies what is felt to be the most critical supply, transmission and substation issues facing the City.

The City of Springville, Utah requested that Electric Power Engineering Associates develop a 10-year electrical system plan to insure that adequate resources are provided to maintain the projected growth of the system for the next ten years. Springville is a Municipal Power City with 8,600 current customers in 2004. As a municipal power system, the “profits”, after operations and reinvestment (capital project) funding is complete, are transferred to the City General Fund to help control property tax requirements. This has proven to be very beneficial and provides a significant portion of the City’s operating funds. This local ownership and control is in contrast to an Investor Owned Utility where ultimate control is often in another state and profits are distributed as dividends to the individual investors and stock holders of the company though out the country.

The City electric power utility was formed in 1904 and owns a combination of 37 MW of hydroelectric plants and reciprocating engine generator sets located within its power system. Power is also supplied from other resources outside of Springville. A 46kV transmission system delivers bulk power to the five distribution substations which serve the residents and power customers. Over the last 15 years Springville City Power has more than tripled its load. In 1988 Springville’s demand was 15.45 MW and by last summer (2003) the system peak demand or load was 47.18 MW. This is an annual growth rate of approximately 7.7%. The present level of demand is nearing the maximum delivery capacity of the transmission system into the City. Continued growth in customer power usage has necessitated ongoing improvements and expansion of the Springville City Power system.

In order to develop the requested Ten-Year Capital Improvements Plan, historical load growth was evaluated, the present system conditions were reviewed and load growth was projected for the next twenty years by the consultant with Springville City Power’s assistance. Next, capacity and reliability factors were taken into consideration in order to develop the necessary proposed expansions to the power supply and delivery systems.

It is important that adequate steps be taken continuously to assure that the current and future loads of the system can be served as requested and maintained in a reliable fashion. While no system can be 100% reliable, customers do expect that the reliability of the system will be quite high. Furthermore, electric outages have negative impacts on the City both economically and socially. Springville has two considerations for anticipating electrical system load growth for the City:

- Power (kW) and Energy (kWh) Procurement
- Electric Transmission and Distribution Delivery

The Springville electric system needs to expand its system in a reasonable and prudent manner to reliably meet future demand and energy growth requirements related to development activity throughout the service area. This expansion requires thorough electric system planning based on expected load growth, reasonable reliability criteria, land acquisition considerations and even some political considerations such as building transmission lines, distribution lines and substations prior to development. Failure to adequately plan, design and construct the electrical facilities ahead of development can lead to costly land procurement, landowner disputes, delays in the projects, substantial legal costs and even prohibition of completing a vital and necessary project.

There is a general common understanding in the electric power industry that continued growth requires continued expansion of the distribution system. This expansion has not been specifically identified and included as being part of the priority projects. General distribution projects tend to be ongoing and provide support to meet the demands of local new development and the increasing power demands of existing customers. Since they do not necessarily provide new capacity and support for just new development, these distribution expansion and upgrade projects are not included in the 10-year CIP Plan or in the associated Impact Fees Study.

Using the considerations listed above, the ten year plan has been developed and categorized below. The priorities indicate project importance and recommended completion windows. Actual implementation is dependent upon funding and actual load growth requirements.

- **Priority 1: High Priority ($1,142,000)** – Recommended to be completed within one year. Money needs to be budgeted immediately and the projects need to be implemented as soon as possible.
- **Priority 2: Moderately High Priority ($520,000)** – Recommended to be completed within two years. However, the priority is high and should be completed earlier if possible.
- **Priority 3: Medium Priority ($1,765,000)** – Recommended to be completed within five years.
- **Priority 4: Low Priority ($2,275,500)** – Recommended to be completed within ten years.
- **Priority 5: Long Term Priority** (no budget provided since outside the 10-year scope of the Plan) – Recommended to be completed within twenty years.

The proposed ten year capital improvement budget is approximately **$5,702,500** in 2004 dollars. Present economic indicators such as fuel cost increases, metal cost increases, concrete cost increases and so forth threaten potentially higher inflation rates in the future. So, over the ten years, actual costs in dollars could be much more..

The City of Springville, Utah requested that Electric Power Engineering Associates develop a 10-year electrical system plan to insure that adequate resources are provided to maintain the projected growth of the system for the next ten years. The principal engineers who managed this project have a combined 65 years of engineering, operations and management experience in the electric power industry. In order to develop the requested plan, historical load growth was reviewed, the present system conditions were reviewed and load growth was projected for the next twenty years by the consultant with Springville City Power's assistance. Next, capacity and reliability factors were taken into consideration in order to develop the necessary proposed expansions to the transmission and distribution systems.

This report summarizes the results of a planning study untaken for the City of Springville. The report will provide the following basic information:

- System Load Growth Considerations
- Discussion on system reliability factors for both the transmission and distribution systems
- Discussion on historical load growth for the system
- Discussion on projected load growth for the system
- Project recommendations for expanding the generation, transmission and distribution system to meet future growth
- Summary of 10-Year Construction Costs

It is important that adequate steps be taken continuously to assure that the current and future loads of the system can be served as requested and maintained in a reliable fashion. While no system can be 100% reliable, customers do expect that the reliability of the system will be quite high. Furthermore, electric outages have negative impacts on the City both economically and socially.

Due to engineering, material procurement and construction time constraints, plans need to be developed for the projects in order to meet future electrical needs. Time constraints for a project can easily involve a number of years for proper budgeting, land procurement, design, material procurement and construction. Therefore, it is common utility practice to develop 5, 10, 15 and 20 year plans. Springville has elected to develop this 10-year plan.

A list of selected and simplified terms and definitions used in this discussion and that of impact fees has been included as Appendix C of this 10-Year Capital Plan.

Springville has two considerations for anticipating electrical system load growth for the City:

- Power (kW) and Energy (kWh) Procurement
- Electric Transmission and Distribution Delivery

The City is fortunate to have a combination of hydroelectric plants and reciprocating engine generator sets so that it can supply a significant portion of the City's electric power and energy requirements for base load, peaking load and emergency loads as the requirements dictate. In addition, the City has ownership interest in the new NEBO Power Station (NPS), has Western Area Power Administration Colorado River hydro generation allocations and other means of obtaining its long term power and energy requirements. This report will not address generation planning. This report will cover the electric transmission and distribution capacity and reliability requirements for the next ten years.

The Electric Transmission and Distribution Delivery system primarily includes all of the following:

- 138 – 46 kV Transmission Substations
- 46 kV transmission lines
- 46 – 12.5 kV Substations
- Power transformers
- 12.5 kV distribution lines
- Distribution transformers

Failure to adequately plan, construct and maintain the transmission and distribution system can result in the following:

- Inability to deliver power when and where required
- Reduced reliability to the City's customers
- Premature equipment failures
- Operating personnel safety concerns
- Safety concerns for the general public

Springville is a Municipal Power City with 8,600 current customers in 2004. As a municipal power system, the “profits”, after operations and reinvestment (capital project) funding is complete, are transferred to the City General Fund to help control property tax requirements. This has proven to be very beneficial and provides a significant portion of the City’s operating funds. This local ownership and control is in contrast to an Investor Owned Utility where ultimate control is often in another state and profits are distributed as dividends to the individual investors and stock holders of the company though out the country.

The City electric power utility was formed in 1904 and has worked diligently to provide reliable, efficient service to its customers. Springville’s initial source of power was from a hydro-generation unit installed at Spring Creek near the mouth of Hobble Creek Canyon. Additional generation was added through the years until in 1986 Springville’s power supply resources included the Canyon hydro generators and the natural gas fired K1 and K2 Enterprise engine-generators at the Whitehead Generation Plant. Combined, these facilities provided the City with a total in-house capacity of about 15.5 MW. This was a close match to Springville’s total peak demand although low stream flows required that additional resources be utilized. The most valuable of which was an allocation from the Federal Power projects associated with the Colorado River and administered by the Western Area Power Administration (WAPA). This resource allocation was secured during the sixties and seventies

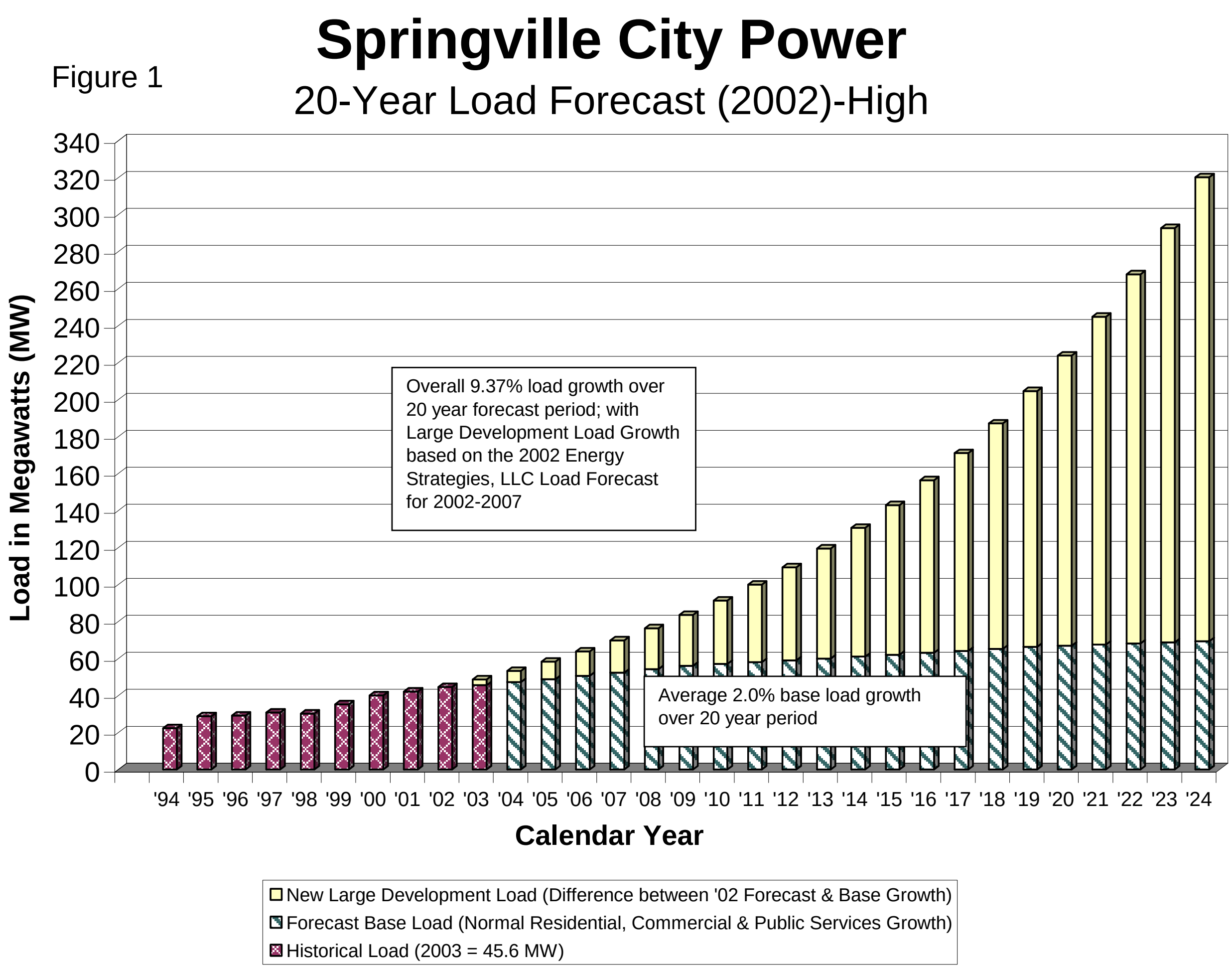
In the early 80’s membership in the Utah Association of Municipal Power Systems (UAMPS) was obtained which provided Springville with support in its various energy marketing efforts and optional participation in selected power projects. Between 1986 and 2001, the City determined that no further in-house or firm-contract generation resources would be acquired and that ongoing requirements would be purchased as needed from the open or spot market either directly or through UAMPS. This took advantage of the seemingly endless glut of low cost interruptible power which flooded the western power markets. Years of heavy precipitation had provided hydro-generation facilities with huge flows of water and resulting cheap “dump” power. The result was low wholesale costs and stable rates for the customer. In the late 1990’s five extremely low cost new surplus generators were offered to Springville for purchase and those units were authorized for purchase, but not for installation and commissioning. A total of 20.5 MW of engine-generator capacity was included in this purchase.

By 2000, the City’s peak demand reached 40.1 MW after two years of 16.6% and 13.9% growth, respectively. That same summer fueled by the adoption of retail wheeling/marketing in California and the rules associated with that deregulation of the power utility industry, the volatile national energy marketing phenomenon led by Enron resulted in runaway spot market prices. Over the period from April 2000 to June of 2001, spot electrical energy costs soared from the rather constant and historically expected low 20mils/kWh ($0.02) to over 244mils/kWh ($0.244). This resulted in severe increases in wholesale power costs for those utilities without ownership in resources or firm contracts for power delivery. Springville like most other power utilities in Utah experienced large increases in wholesale power costs. These costs exceeded the utility’s ability to absorb the financial obligation without rate increases. The authorization to proceed with installation of the stored generation was given to Springville City Power and work began immediately to install and commission the units. With the available in-house generation, a savings of over $30 million was realized from May of 2000 through December of 2002. This reflects the cost difference between the spot market price available to Springville and the cost of generation from its own resources. These generators were purchased and installed at a total cost of approximately $4.2 million.

Given the preceding background, Springville City Power has more than tripled its load over the last 15 years. In 1988 Springville's demand was 15.45 MW and by last summer (2003) the system peak demand or load was 47.18 MW. This is an annual growth rate of approximately 7.7%. Over the last four years from the summer of 1999 (40.1 MW) to the summer of 2003 (47.2 MW) the rate of growth slowed considerably to 4.1%. This growth in new and expanding customer load demand requires that the infrastructure be expanded to supply the increased service requirements.

Based on continued trends towards a slow economy and growth especially in the commercial area, Springville has been concerned that the previous five-year load forecast developed in 2002 is too aggressive. With extrapolation through the next ten years, that forecast projects a 130.8 MW load in 2014. The summary graph is presented in Figure 1 below. The tabular and graphic results of the 2002 forecast to 2007 and their extrapolation through 2024 are included in Appendix A of this report. This is designated as the "High" growth scenario.

Figure 1

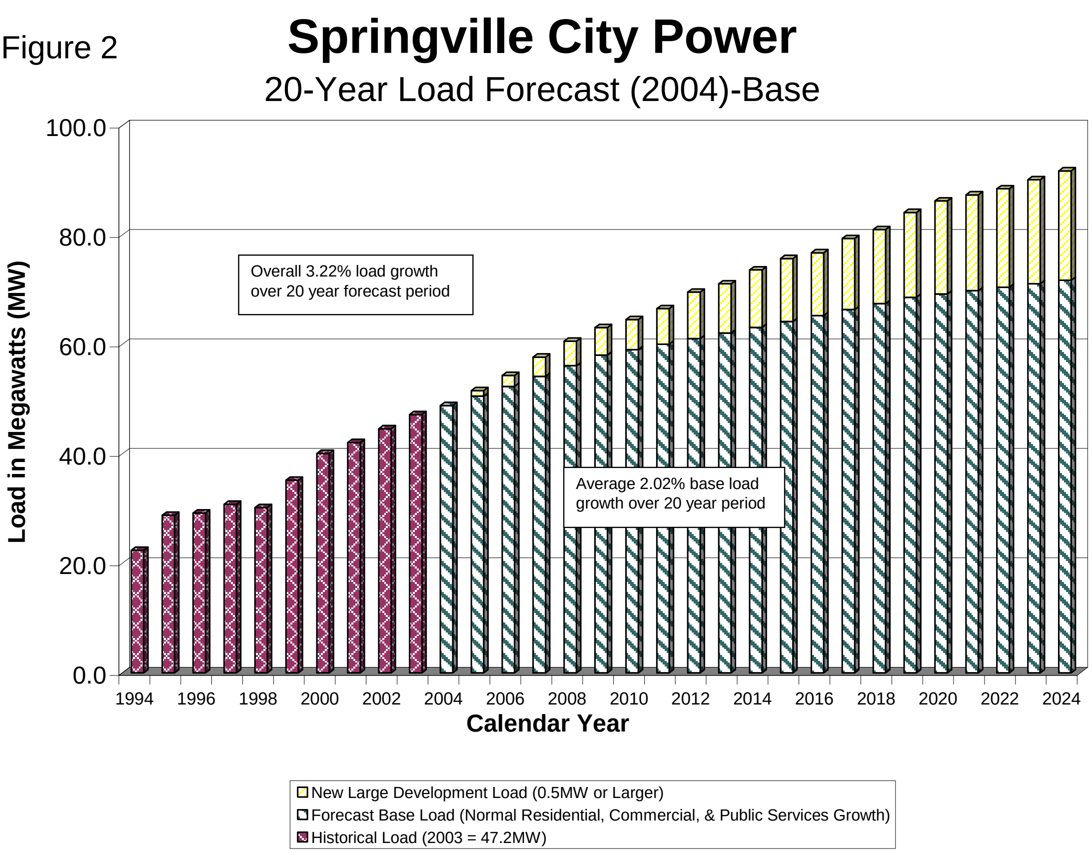


Springville recently completed annexation of a significant section of county on the west side of I-15. The interchange at I-15 and 400 South has been the site of significant development over the last five years, but as was indicated above, the rate of development in commercial facilities has slowed. In some parts of the city, prime commercial building vacancy has continued for several years. The development of residential housing has been quite robust having just passed through a period of the lowest mortgage rates in more than three decades. Significant numbers of new residential housing developments are in the process of requesting approval and permitting from the City. This mixed growth has prompted a cautious review and approach by Springville City Power as it prepared for development of the new 20 year load forecast included as part of this study.

In cooperation with Springville City Power, Electric Power Engineering Associates has prepared a "Base" 20 year load forecast which is conservative in growth, but which attempts to provide a sense of where and when development will occur within the electrical system's service area. Within the forecast, the base or normal load growth is correlated to the projected population growth of Springville as provided by the Utah Governors Office of Planning and Budget. The 2003 demand was approximately 47.2 MW and that load is expected to grow to approximately 73.6 MW by the year 2014. The average growth is expected to be only 3.22% per year over the next 20 years. Based on the last 20 years, this may be a conservatively low estimate. This could change if the industrial sector growth increases over present projection. It is likely that actual loads will be between Base & High.

The summary graph is presented in Figure 2 below. The tabular and graphic results of the 2004 forecast to 2024 are included in Appendix A of this report. This forecast is designated as the "Base" growth scenario.

Figure 2



If the actual load growth is greater than the base scenario, it is likely that the projected Capital Improvement Projects (CIP) noted below will need to be accelerated. As stated, these projects provide for the forecast load growth due to new development. There is also an element of system reliability which will need to be addressed as funding allows. For example, as the total system peak load increases, the ability of the power system to survive the loss of any single critical component of its power delivery system, without extended power outages, decreases. This is sometimes referred to as being able to survive an "N-1 Contingency". This is an operational philosophy that the available system capacity should exceed actual usage by at least the rated load carrying ability of any single component of capacity whose loss would interrupt delivery of bulk power to the utility. This could be a critical transformer, a section of power line, or another key component of the electrical system. In Springville's case, the main limitation at the present time is transmission capacity into the city's power grid. The loss due to vehicle accident, fire or other cause of one of the transmission feeders into the city would be an N-1 event. While a concern, of more critical importance is expanding bulk power delivery capacity to the Municipal Power System to serve immediate new load requirements system-wide.

With the completion this year of the proposed second 46kV incoming feeder at Evergreen to receive power from the new Dry Creek Transmission Substation, system capacity will near 90 MVA (45MVA+ per feeder). The current load of 47.2 MW is equivalent to nearly 50 MVA at 95% power factor, which indicates that Springville needs the projects in the Plan to provide for continuing load growth. The capacity related projects proposed in the 2004 Ten-Year CIP Plan will provide expanded capability to serve Springville City Power's customers. Given normal operating and safety limitations and considering the issues of system reliability, a third transmission line should be added to deliver power to Springville before total system load exceeds 77MW. The ten-year plan included in this report provides for construction of a third transmission line to provide this added bulk power delivery into the City.

The Springville electric system needs to expand its system in a reasonable and prudent manner to reliably meet future demand and energy growth requirements related to development activity throughout the service area. This expansion requires thorough electric system planning based on expected load growth, reasonable reliability criteria, land acquisition considerations and even some political considerations such as building transmission lines, distribution lines and substations prior to development. Failure to adequately plan, design and construct the electrical facilities ahead of development can lead to costly land procurement, landowner disputes, delays in the projects, substantial legal costs and even prohibition of completing a vital and necessary project. Since distribution expansion and upgrade projects do not necessarily provide new capacity and support for just new development, they are not specifically included in the 10-year CIP Plan or in the associated Impact Fees Study.

Using the considerations listed above, the ten year plan has been developed and categorized below. The priorities indicate project importance and recommended completion windows. Actual implementation is dependent upon funding and actual load growth requirements.

- **Priority 1: High Priority** – Recommended to be completed within one year. Money needs to be budgeted immediately and the projects need to be implemented as soon as possible.
- **Priority 2: Moderately High Priority** – Recommended to be completed within two years. However, the priority is high and should be completed earlier if possible.
- **Priority 3: Medium Priority** – Recommended to be completed within five years.
- **Priority 4: Low Priority** – Recommended to be completed within ten years.
- **Priority 5: Long Term Priority** – Recommended to be completed within twenty years.

Priority 1: High Priority (Year 1)

Priority 1 is the highest priority and is assigned to projects that are of high importance. All items in priority 1 need to be placed in service as soon as practical and all within the first year.

1. **Evergreen Substation Upgrades**: Evergreen Substation has a single transmission tap line rated at 45 MVA for interconnection to outside power for Springville City Power. This tap can be switched between alternative 46 kV feeds to Spanish Fork and Dry Creek Substations. With projected growth in summer loads, peak loads will exceed the single tap line's rated capacity. A second feed into Springville is required to serve new load growth. Therefore, the following upgrades are required.

    a. Install a second incoming 46 kV breaker. Presently, Evergreen Substation is the single tie to the outside world. The design is such that only one 46 kV transmission line, either Spanish Fork or Dry Creek Substation, can supply power to the substation. Springville City Power is presently capacity limited at Evergreen Substation. That limit is in the 45 MVA range and the 2003 peak load was 47.2 MW or 49.7 MVA assuming a 0.95 PF.

The estimated cost for the second breaker installation is $85,000 including the cost of a new breaker, line protective relays, switches, steel, concrete and labor.

b. Connect the Dry Creek line to the new 46 kV breaker after completion of the incoming breaker.

   The estimated cost for the termination of the Dry Creek Line into the Evergreen Substation is $35,000.

c. Install new line protection relays on the Spanish Fork Line and the Springville 46 kV feeders at Evergreen Substation. This is part of the requirement for the installation of the second circuit into Evergreen Substation.

   The estimated cost for the Spanish Fork and Springville Relaying at Evergreen is $60,000.

   The total estimated cost for the expansion at Evergreen Substation is $180,000.

Responsibility: 100% growth related capacity addition.

2. **Power Factor Correction Capacitors**: One of the most effective ways to free capacity on a transmission, substation or distribution system is the placement of power system capacitors at proper locations. The determination of the proper location is usually the most difficult aspect of installing the power factor correction capacitors. Ideally, the proper location is right at the load, but this can become difficult and costly. For example, capacitors placed on 480 Volt systems can cost as much as $30/kVAR or more. On the other hand, the installation of capacitors on a distribution system can be very economical and be as low as in the $3/kVar range for fixed, distribution capacitors.

   Assuming a load in the near future in excess of 50 MVA with a 0.95 PF, that equates to approximately 48 MW and 16 MVAR for maximum power flow. Then assuming 60% of that load and the same power factor under light loading conditions, the minimum load condition equates to approximately 29 MW and 9 MVAR. Fixed capacitors in the range of 6000 kVar for constant application to the system, and switched capacitors in the range of 6000-9000 Kvar total for switching into service as needed during periods of heavy system loading, could be installed on the distribution system.

Presently, Springville has approximately 2400 kVAR of capacitors on its system. They are composed of the following:

- Four (4) 300 kVAR fixed two of which are located on circuits 103 and 106 out of Evergreen Substation.
- Two (2) 600 kVAR switched by VAR control located on circuits 501 and 503 in the North Industrial Park.

The proposed fixed capacitors should be installed so that a minimum of 6000 kVAR of fixed capacitors are installed, the cost is estimated to be $30,000.

Upon completion of the 6000 kVAR of fixed capacitors, the switched capacitors should then be installed. Approximately 9000 kVAR of switched capacitors should be installed. The installed cost of those capacitors is $90,000.

The total capacitor bank installation project is estimated at $120,000.

Responsibility: 100% growth related capacity addition.

3. **West Substation Upgrade**: West Substation is nearing full capacity. The 2003 peak load was near 90% of the rated capacity. The present transformer size is 5/6.25-7.0 MVA. The substation has two feeders with reclosers. The substation should be expanded to a larger transformer. Since Springville has standardized on 12/16/20-22 MVA transformer, that should be the next transformer installed. In addition, the substation should be expanded by utilizing a Power Distribution Center (PDC) with four feeder breakers. That would allow two additional feeders to be served from the substation.

   The cost estimate for the upgrade is:

12/16/20-22.4 MVA Transformer...............	$300,000
44 kV Circuit Switcher/Breaker……........	$45,000
PDC with Four Feeder Breakers……….....	$210,000
Remainder of Substation & Labor……......	<u>$150,000</u>
TOTAL	$705,000

   Responsibility: 100% growth related capacity addition.

4. **Engineering Tasks - System Documentation of Drawings, Reliability Indices and System Contingency Plan**: Because of continued load growth, Springville City Power's electrical infrastructure is nearing the point that without proper optimization transmission capacity will limit the ability to deliver additional levels of power to their customers. In order to properly optimize system operation and maintenance, system documentation needs to be such that ready access is available to correct as-built drawings and other system documentation. System documentation would include maps of transmission feeders, switching facilities, line protection, transformers, and similar infrastructure. This is a high priority

item since inadequate drawings and documentation can lead to poor reliability and utilization of available resource capability and may result to slow troubleshooting and restoration of service. This task is estimated to cost $120,000.

Software..	$70,000
Field Inventory (3 Interns x 12 weeks x $10/hrs.)..	$15,000
Supervision for Field Inventory.............................	$10,000
CADD Mapping and Data Base Development.......	$25,000
TOTAL	$120,000

Additional tasks under this project include developing reliability indices to track outages, their frequency, duration, and causes. This information assists in overall planning and operation to provide improved capacity utilization and reliable power delivery. Development of contingency plans for loss of power transformers, loss of transmission lines, loss of substations and loss of major distribution feeders is needed due to load growth using previously available capacity. This will also assure rapid response and power restoration after loosing a critical component of the power system. This task would include operations, maintenance and planning strategies, guidelines, and procedures. Combined these two tasks will costs $2,000.

In addition, the following tasks need to be completed at the Whitehead Plant to allow full generation capacity to be utilized at a cost of $15,000.

1. Engineering Solution on Whitehead Plant 489 relay false tripping
2. Relay testing of the non-documented Basler Relays at Whitehead.

The cost estimate for the engineering tasks is estimated to equal $137,000.

Responsibility: 100% operations reliability.

Priority 2 – Moderately High Priority (Years 1-2)

1. **Stouffers Substation Upgrade**: Springville provides 46 kV service to the Stouffers Substation. The existing power facility does not provide for feed through capability of the 46kV feeders and limits capacity utilization. This project provides the functionality needed to release available system capacity and to optimize operations to serve Springville City Power's growing customer load.

   Stouffers is Springville's largest load and it requires extremely high reliability. A sustained power outage could result in substantial losses due to food spoilage from loss of refrigeration. Stouffers' has elected to pay a substantial monthly demand charge premium to assure that power will be restored WITHIN 2 HOURS. That amount is estimated at $33,550/month or slightly more that $400,000 annually.

The following items are of a moderately high priority and should be completed as soon as practical:

a. Installation of Motor Operated Switches, Automatic Sectionalizing and Automatic Throw-over. Two motor operated, 46 kV switches, three 46 kV voltage transformers and a control system. The estimated cost for this project is $30,000 and utilizes some existing equipment.

b. Installation of high resistance grounding with alarm. The present transformer secondary is a solidly grounded, 4.16 kV system. As a result, high available fault currents for ground faults are present which can quickly propagate into a multiple phase fault. This thru-fault can and has caused tripping of the 46 kV feeders. Installation of high resistance grounding can minimize the fault current and lessen the likelihood of a customer related fault causing an outage on the transmission system. This task will also result in a major improvement to Stouffer's reliability due to secondary faults. Over 98% of all industrial faults originate as a line to ground fault. Installation of the high resistance grounding will allow the system to continue for a short period of time until the fault can be located and the problem remedied. This project is related to the system capacity improvement need in North Springville. The estimated cost for this project is $40,000.

c. Installation of transformer Circuit Switchers. Transformers rated above 7.5-10 MVA should be protected utilizing high speed protective relays and not fuses. System reliability is affected by fusing transformers rated a large as those at Stouffer's (12/16/20 MVA). With a 300E fuse, the actual operating current for a fuse to blow could be in excess of 600 Amps. Remote 46 kV ground relays may operate faster causing an entire line to trip prior to the fuse blowing on a 12/16/20 MVA transformer. Therefore, the failure of one transformer at Stouffers could result in a full outage to the plant and adjacent substations. Installation of circuit switchers would allow automatic throw-over and quick restoration of service to Stouffers and other customers. The estimated cost for this project is $150,000.

   The total cost for the Stouffer's project is $220,000.

Responsibility: 60% growth related capacity addition; 40% operations reliability.

2. **Whitehead Power Plant Substation –** The Whitehead Substation is a critical facility for Springville Power and Light in that all of the City's generation, with the exception of the hydro plants, is located in the Power Plant. The Whitehead Substation appears to have the equipment and facilities to be expanded into an in-and-out substation that would improve the system capacity and reliability. The addition of in-and-out capability would improve both generator and 46kV operating capability to serve new loads on the north and west sides of Springville. The following modifications are required:

a. Installation of three circuit switchers, one on each of the three transformers
b. Modify 46 kV line to provide two, incoming lines
c. Modify Line Protection

The cost estimate for this project is $300,000.

Responsibility: 80% growth related capacity addition; 20% operations reliability.

Priority 3 - Medium Priority (Years 3-5)

1. **46 kV Line Expansion to proposed IPP Substation** - Springville is growing to the west of the city and plans need to be made to serve that load. Future load growth in this area will ultimately require a 46-12.5 kV substation and the City is in the process of acquiring property. Although the substation may not be required for several years into the future, there is a need to consider the early installation of the 46 kV transmission line prior to the development of the land between Dry Creek Substation and the proposed IPP site. If the line is constructed prior to the development in that area, the cost of the land and the approval process will go much quicker.

   Therefore, it is proposed to complete the 46 kV transmission line as soon as is practical. Presently, approximately 1500 feet of structures have been installed exiting Dry Creek Substation and going west. Approximately 8000 feet of additional line is proposed. Serious consideration should be given to utilizing 138 kV construction for possible future interconnection to Provo to the North. The line should be constructed with 138 kV insulation and operated at 46 kV. The cost of the line can vary due to the ruling spans, the type of towers and conductor sizes. With that in mind, a reasonable estimate for 8000 feet of line constructed at 138 kV in an urban area is $440,000 including easements. Delaying this construction could ultimately force the line to be placed underground and the cost could approach $1.6 million dollars.

   The cost of the 46 kV line between Dry Creek and IPP Substation is estimated to be $440,000.

   Responsibility: 100% growth related capacity additions.

2. **IPP Substation** – The IPP Substation will be used to supply most of the future commercial and residential load growth to the west of the City. As such, it has the requirement to supply a substantial amount of future load. The substation should be designed with 138 kV insulation, should have in-and-out circuit breakers and should ultimately be built as a two transformer substation. Assuming that one 46-12.5 kV transformer will be initially installed and that the substation will have future expansion capability to meet the requirements stated above, the estimated cost of the substation is $1,250,000.

   Responsibility: 100% growth related capacity additions.

3. **900 North Substation Circuit Switcher Installation** – Power system capacity constraints require that substation protection be optimized to provide maximum output. By installing relaying and a 46kV circuit switcher or breaker, the full capacity of the North Substation can be utilized. This project will also improve system reliability to serve existing customers and the continuing customer load growth.

   The estimated cost for the circuit switcher installation at North Substation is $75,000.

Responsibility: 30% growth related capacity addition; 70% operations reliability.

Priority 4 - Low Priority (Years 6-10)

1. **Expansion of 46 kV Line to Stouffer's Substation** - Ultimately, the 46 kV line between Dry Creek Substation and the new IPP Substation will need to be expanded to the north and should interconnect in a new addition at or near the Stouffer's Substation. This expansion will complete the Westside Transmission Loop and provide needed capacity to support the north portion of the Springville City Power service area. Two alternatives exist in completing the 46 kV Loop:

   a. Extend a line approximately 500 feet to the north of the IPP Substation. Reconstruct the present Utah Power (UP) 46 kV line to a double circuit construction for a length of approximately 10,000 to the Northern Springville City limits. The upgrade the East-West UP line to double circuit and run the line approximately 3600 feet to the D&RG Railroad right of way. Then construct a new 46 kV line south 2000 feet to Stouffer's. Serious consideration again should be given to constructing the line with 138 kV insulation and operate the line initially at 46 kV.

      The cost of this expansion would be highly dependent on Utah Power. It is estimated that this cost option with required new easements would be

500 Feet Single Circuit Line….........	$27,500
10,000 Feet Double Circuit Line........	$800,000
3600 Feet Double Circuit Line….......	$288,000
2000 Feet Single Circuit Line…….....	$110,000
TOTAL Option a	$1,225,500

   b. Install 6600 feet of new O/H line to the north and then construct 6,900 feet of U/G line including easements.

6,600 Feet O/H line……………...…	$363,000
6,900 Feet U/G line………………...	$1,481,400
TOTAL Option b	$1,844,400

In addition to one of the above options, an expansion to the IPP Substation would be required and an addition to the Stouffer Substation or a new substation would be required near Stouffers. The cost of the IPP expansion, assuming that it is originally built with plans for the future north line bay would be approximately $250,000. The new northern substation would be primarily a switching station and would cost approximately $800,000. The total of new substation expansions for this project would be approximately $1,050,000.

The cost of the Expansion of the 46 kV line to Stouffers assuming option "a" is:

IPP Substation Addition..	$250,000
Option "a" line..	$1,225,500
Stouffer end Line Termination...............................	$800,000
TOTAL 46 kV line expansion to Stouffer's	$2,275,500

Responsibility: 100% growth related capacity additions.

Priority 5 – Long-Term Priority (Years 10-20)

[*Note that these projects are not included in the 10-Year Capital Improvement Plan because their construction schedule is beyond the 10 year window.*]

1. **138kV Westside Conversion** – As suggested earlier in the "Projected Load Growth Discussion" and in Priority 3, project 1 – "46kV line expansion to proposed IPP Substation", the future ability of Springville City Power to provide reliable power to its customers is dependent upon having adequate capacity in the bulk power delivery system. The 46kV transmission system's delivery capacity will become subject to compromise by an N-1 event when total system load approaches 125MVA or about 118 MW as projected in 2013 under the high load growth scenario forecast. If actual loads are greater than the base load growth scenario forecast, then the conversion of the Westside 46kV loop to 138kV will become critical to Springville's overall delivery capability and reliability. This project includes the addition of a 138kV-12.5kV substation transformer at the IPP Substation, Conversion and extension of the Westside 46kV termination at Dry Creek to 138kV and installation of a 138kV to 46kV power transformer at the proposed "North Industrial Switchstation" to provide bulk power to the existing 46kV system at the Stouffers Substation.

   a) 138-12.5kV substation transformer at IPP would include the installation of a new transformer and Power Distribution Center (Switchgear Building) at the IPP site. This would be coordinated to minimize system down time and interruption of existing service from the original 46-12.5kV transformer which will be removed and potentially reused in another part of the Springville system such as 900 North Sub. Cost is estimated at $705,000 (similar to West Substation Upgrade budget).

b) Conversion of the Westside 46kV Dry Creek Transmission Line to 138kV would include one of two options, either:

i) Extension of the existing Westside line conductors (insulated at 138kV) to the spare 138kV bay at Dry Creek and installation of a 138kV power breaker with controls and relaying. Estimated at:

Breaker addition ……….........…………………………….………	$130,000
Transmission line extension on steel structures …..…….........	<u>$100,000</u>
TOTAL	$230,000

ii) Installation of a new double bay 138kV switch structure on the west side of the Dry Creek Substation with an extension from the existing spare 138kV bus. This new structure would provide 138kV feeder capability for both Springville and Spanish Fork. Construction is estimated at;

Extension to Dry Creek 138kV Bay..	$230,000
New Double Bay switchstation less the Spanish Fork Breaker...	<u>$670,000</u>
TOTAL	$900,000

c) Addition of a 138-46kV power transformer at the North Industrial Substation and intertie with Provo City Power would include installation of the transformer in a pre-designed bay which would be converted from 46kV to 138kV upon re-energization of the line from IPP Substation. Original installation of equipment at 138kV spacing and insulation levels will minimize costs for conversion to 138kV. Estimated cost would be:

36/48/60-67.2 MVA 138-46kV Transformer with LTC.................	$500,000
Secondary 46kV protection and breaker....................................	$75,000
Remainder of substation and labor...	<u>$100,000</u>
TOTAL	$675,000

Total estimated project cost would be **$1,610,000** assuming the138kV Dry Creek extension will not require the new switchstation installation.

Responsibility: 100% growth related capacity additions

Summary of Costs - The proposed ten year capital improvement budget is approximately **$5,702,500** in 2004 dollars. Present fuel costs, metal cost increases, concrete cost increases and so forth are indications of potentially higher inflation rates. So, over the ten years, actual costs in dollars could be much more. Table 1 summarizes the costs of the four priorities:

Priority 1 - High	
1- Evergreen Substation Upgrades Project..................	$180,000
2- Power Factor Correction Project.............................	$120,000
3- West Substation Upgrade.......................................	$705,000
4- Engineering Tasks..	$137,000
TOTAL Priority 1	**$1,142,000**
Priority 2 – Moderately High	
1- Stouffer Reliability Improvements...........................	$220,000
2- Whitehead Substation...	$300,000
TOTAL Priority 2	**$520,000**
Priority 3 – Medium	
1- 46 kV Line Extension to IPP...................................	$440,000
2- IPP Substation..	$1,250,000
3- North Substation Circuit Switcher Addition.............	$75,000
TOTAL Priority 3	**$1,765,000**
Priority 4 – Low	
1- Expansion of 46 kV line to Stouffer's Substation.....	$2,275,500
TOTAL Priority 4	**$2,275,500**

Table 1 – Ten Year Capital Improvement Projects – Cost Estimates

Continued growth and reliability of the Springville Power System requires a consistent, knowledgeable and diligent commitment to the Capital Improvement and Upgrade of the supply, transmission and distribution resources of the City. As indicated earlier in this report, Springville is nearing the point of continued load growth exceeding the ability of its power system to provide the service desired and expected and deserved by its citizens. Wise decisions in the past and dedicated, skilled employees have provided the needed support to bring the system to this point, but Springville is no longer a small rural community. It has international businesses and technically capable residents who depend upon reliable electrical service. This report identifies what is felt to be the most critical supply, transmission and substation issues facing the City. There is a common understanding that continued growth requires continued expansion of the distribution system. This expansion has not been specifically identified as being part of the priority projects. General distribution projects tend to be ongoing and provide support to meet the demands of new development and the increasing power demands of existing customers. Since they do not necessarily provide new capacity and support for just new development, these distribution expansion and upgrade projects are not included in the 10-year CIP Plan. The following are several recommendations and comments specifically related to the distribution system. They are intended to provide guidance, support and direction so that improved overall system operations, efficiency and reliability can be achieved.

1. Distribution system mapping and documentation is needed to provide the tools required for improved reliability and outage restoration. It is recommended that Springville City Power consider implementation of a system-wide Geographic Information System (GIS) in the near term. Such an effort is partially provided under the Priority 1, Item 4 Engineering Tasks which provides for mapping and documentation of the Supply, Transmission and Substation infrastructure of the Utility.

2. The distribution backbone or main feeders should be upgraded in size to allow 600a (13MVA) operation between adjacent substation circuits. Most of the existing overhead distribution system consists of 340a (7MVA) conductor. This upgrade has several major advantages. The first and perhaps most important to reliable operations is the ability to provide backup support to adjacent circuits in the event of an outage or a planned maintenance related interruption. Second, the larger capacity provides greater load delivery capability and reduces line loss and voltage drop. Third, the added strength provides better durability and therefore reliability in avoiding failure due to environmental or external influences.

3. Underground distribution in the North Industrial Park is aging. The nearly 20 year old XLP, jacked concentric neutral cable is partially direct buried and partially in thin walled conduit. Cross linked polyethylene (XLP) cable is susceptible to accelerated failure when installed in constantly wet environments such as in the North Industrial Park area. Normal life for XLP cable is about 20 years. The lack of a backup circuit north of SR-75 greatly limits the ability to restore service in a reasonably short time after failure or to switch loads to other circuits during maintenance or operations activities. It is recommended that steps be taken to continue circuit 501 North along the railroad, across SR-75 (either overhead, if clearances allow, or underground through the viaduct) on the existing 46 kV pole line to Stouffers. The distribution line

would then be extended underground west along Raymond Klauck Way to the existing underground distribution system.

4. System-wide easements and Right of Way should be modified and standardized: Transmission = 40’ total, 20’ either side of centerline; Distribution (OHL and UG) = 16’ total, 8’ either side of centerline.

5. SCADA Data Collection and logging should be enhanced to include regular logging of the entire system including generation, substation, and feeder information for both transmission and distribution circuits. This information is critical in being able to monitor, evaluate and optimize the operation of the power system. The result would be better power quality, improved system losses and more effective operations planning for both day to day needs and longer term maintenance and upgrade need projections.

6. Pole Plant inspection and maintenance would provide a reference to predict pole replacement needs prior to line failures due to wind, etc. This would involve a pole by pole inspection and possibly treatment to kill fungus and mold and to prolong the life of the pole plant in general.

7. Distribution/service transformer loading should be verified to optimize the number of services attached to a single service transformer. Typical loading should be 70-80% or more of the rated capacity.

8. Outage Management tracking and logging should include computer tracking or logging of outages and their location, duration, cause and the number of customers affected. This will assist in confirming system reliability and to provide support for distribution system improvement planning.

9. The East 46 kV loop uses 4/0 ACSR conductor rated at approximately 26 MVA compared to the West 46 kV loop’s 477 ACSR with a 51 MVA rating. This lower rated east side line does affect system flexibility, operations and the ability to serve load growth on the east and north sections of the city. During 2003, the 900 North and Compound substations had loads totaling about 17 MVA. Although normally fed from the West loop, Stouffers’ total load is about 11 MVA so that during scheduled maintenance or emergency switching the East side loop would approach or exceed maximum capacity. The addition of the West Fields Transmission loop will minimize any adverse effect of the smaller east side line, but, if the West Fields line is not built then the east side 46 kV line should be reconductored and rebuilt (as necessary) to the 477 ACSR system standard. This will improve system capacity to serve load growth and will enhance overall system reliability.

Electric Power Engineering Associates has relied upon cost data and other information provided by Springville City Power during the preparation of this document and its supporting work product. While we have no reason to believe that the information provided to us, and upon which we have relied, is inaccurate in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness. Electric Power Engineering Associates reserves and retains all rights to this work product but licenses Springville City Power to use the work product in its normal activities.

APPENDIX A: Load Study Detail

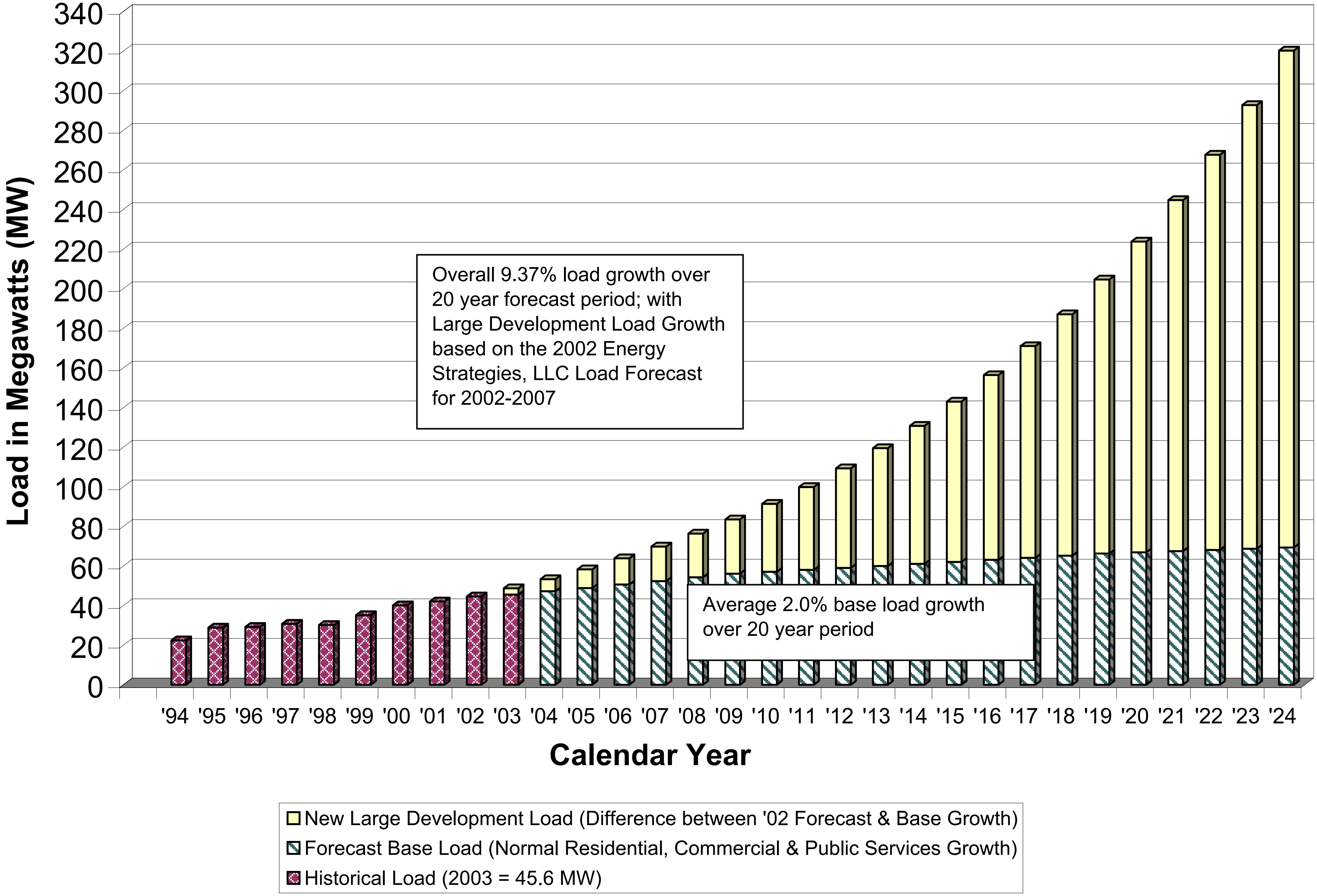
Part A:

Springville City Power
Ten-Year Capital Plan

May 2004

Springville City Power

20-Year Load Forecast (2002)-High



SPRINGVILLE CITY POWER

2002 20 YEAR LOAD FORECAST - HIGH

May 14, 2004 - BBD-Electric Power Engineering Associates

Calendar Year	Actual Demand MW	Base Load MW	Accumulated Point Load MW	Point Load MW	Forecast Demand MW	% chg from prev.	Actual Energy MWH	Forecast Energy MWH	% chg from prev.	Actual Annual % LF	Forecast Annual % LF	% chg from prev.	Comments
1994	22.4						116,790.0			59.5			
1995	28.8						137,654.0			54.6		-8.24	
1996	29.2						163,467.0			63.7		16.67	
1997	30.8						171,931.0			63.8		0.16	
1998	30.2						181,435.0			68.6		7.52	
1999	35.2						194,605.0			63.1		-8.02	
2000	40.1						213,282.0			60.7		-3.80	
2001	42.1						221,618.0			60.1		-0.99	
2002	44.6						234,953.0	222,875.6		60.2	57.1	0.17	
2003	45.6		3.2	3.2	48.8	9.4 a		232,382.9	4.3		54.4	-4.68	
2004		47.2	3.0	6.2	53.4	17.1		242,313.2	4.3		51.9	-4.69	3.53% Utah Governor's Office Planning & Budget - Aug '02
2005		48.9	3.3	9.5	58.4	9.4		252,409.0	4.2		49.5	-4.55	" "
2006		50.6	3.8	13.3	63.9	9.4		263,579.0	4.4		47.2	-4.77	" "
2007		52.4	4.2	17.5	69.9	9.4		275,187.1	4.4		45.0	-4.56	" "
2008		54.2	4.7	22.2	76.4	9.4		287,306.4	4.4		42.9	-4.61	" "
2009		56.2	5.2	27.4	83.6	9.4		299,959.4	4.4		41.0	-4.54	" "
2010		57.1	6.9	34.3	91.4	9.4		313,169.7	4.4		39.1	-4.54	1.68% Utah Governor's Office Planning & Budget - Aug '02
2011		58.1	7.6	41.9	100.0	9.4		326,961.8	4.4		37.3	-4.54	" "
2012		59.0	8.4	50.3	109.3	9.4		341,361.3	4.4		35.6	-4.54	" "
2013		60.0	9.3	59.5	119.6	9.4		356,394.9	4.4		34.0	-4.54	" "
2014		61.0	10.2	69.7	130.8	9.4		372,090.6	4.4		32.5	-4.54	" "
2015		62.1	11.2	81.0	143.0	9.4		388,477.6	4.4		31.0	-4.54	" "
2016		63.1	12.4	93.3	156.4	9.4		405,586.3	4.4		29.6	-4.54	" "
2017		64.2	13.6	106.9	171.1	9.4		423,448.4	4.4		28.3	-4.54	" "
2018		65.2	15.0	121.9	187.1	9.4		442,097.2	4.4		27.0	-4.54	" "
2019		66.3	16.4	138.3	204.6	9.4		461,567.3	4.4		25.7	-4.54	" "
2020		66.9	18.6	156.9	223.8	9.4		481,894.8	4.4		24.6	-4.54	0.89% Utah Governor's Office Planning & Budget - Aug '02
2021		67.5	20.4	177.3	244.8	9.4		503,117.6	4.4		23.5	-4.54	" "
2022		68.1	22.3	199.6	267.7	9.4		525,275.0	4.4		22.4	-4.54	" "
2023		68.7	24.5	224.1	292.8	9.4		548,408.3	4.4		21.4	-4.54	" "
2024		69.3	26.8	251.0	320.3	9.4		572,560.3	4.4		20.4	-4.54	" "

Assumptions:
* Base Load escalates at the estimated population growth rate as provided by the Utah State Governor's Office of Planning & Budget (2002). Calendar Years 2004-2009 escalates at 3.53%/yr; Calendar Years 2010-2018 escalates at 1.68%/yr; Calendar Years 2019-2024 escalates at 0.89%/yr.
* Load Factor is a tool to compare system demand and energy consumption. It has no affect on the demand forecast and so does not influence Impact Fee calculations. Annual Load Factors for 1994-2002 are from actual data; for 2002-2007 the Load Factors are as given in the 2002 Load Forecast by Energy Strategies, LLC; For 2008-2024 the Load Forecast is calculated from Forecast Annual Energy and Forecast Demand.
* Energy is calculated using the energy escalation factor established in the 2002 Load Forecast.
* Point Load is calculated as the annual difference between the Forecast Demand with growth factors provided by the 2002 Load Forecast and the Base Load with growth factors provided by the Utah State Governor's Office of Planning & Budget 2002.
* Accumulated Point Load is a running summation of the current and previous year's Point Loads.
* Forecast Annual Percent Load Factor deescalates at the growth rate provided in the 2002 Load Forecast.

a "% change from previous" indicates percentage change between prior year's actual and the current year's forecast demand as included in the 2002 Load Forecast.

Observation:
* Springville's Actual Load Factor fluctuated widely over the available nine year history (1994-2002), but it tended to average around 61%. The steep reduction proposed in the 2002 Forecast does not appear consistent with actual operating experience.

Actual data by Springville City Power

Projections from 2002 Load Forecast by Energy Strategies, LLC

SPRINGVILLE CITY POWER

2002 20 YEAR LOAD FORECAST - Graph Data

May 14, 2004 BDD-Electric Power Engineering Associates

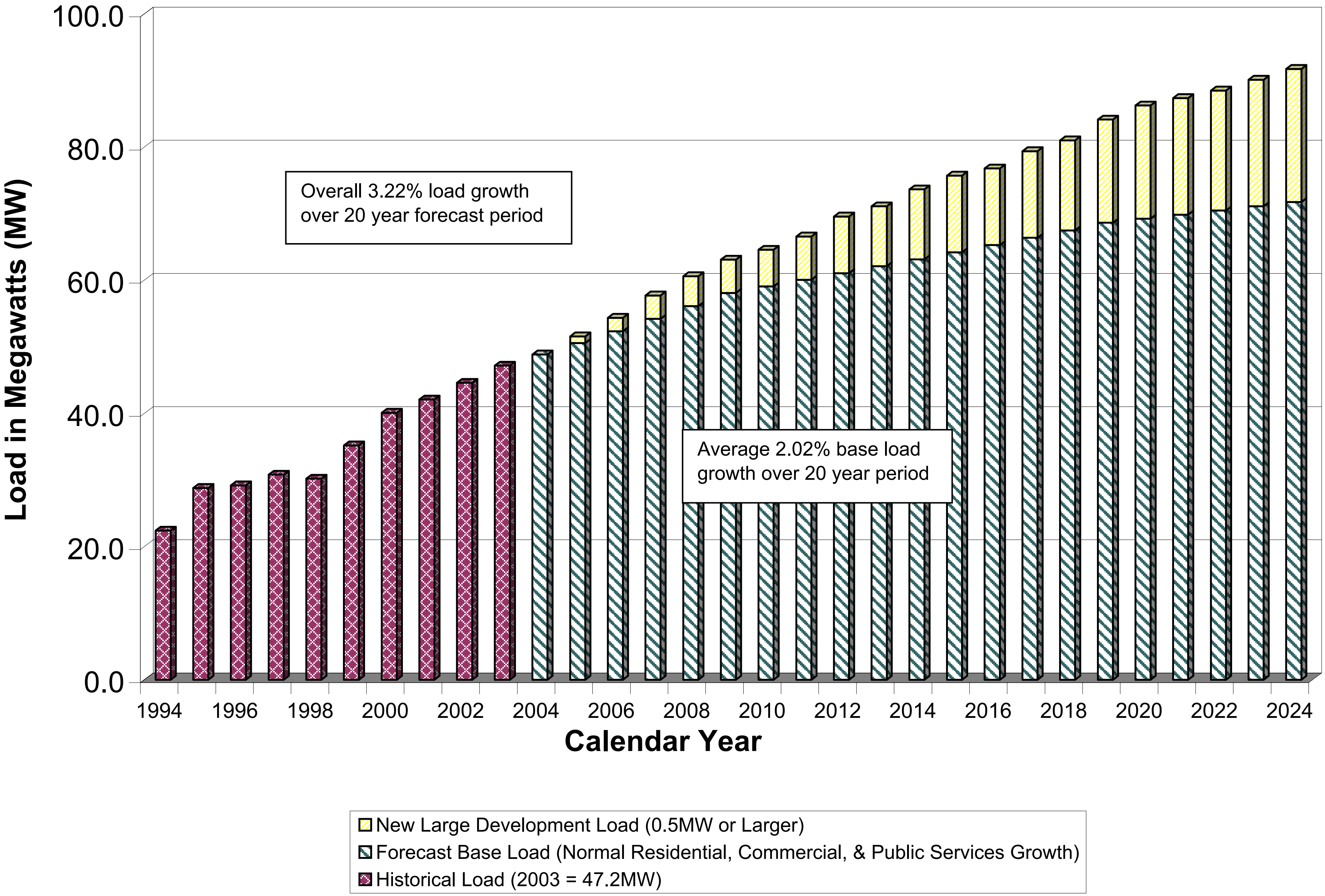
Calendar Year	Historical Load (2003 = 45.6 MW)	Forecast Base Load (Normal Residential, Commercial & Public Services Growth)	New Large Development Load (Difference between '02 Forecast & Base Growth)	Forecast Demand (Projection based on 2002 Load Forecast by Energy Startegies, LLC)	Point Load	COMMENTS
'94	22.4					
'95	28.8					
'96	29.2					
'97	30.8					
'98	30.2					
'99	35.2					
'00	40.1					
'01	42.1					
'02	44.6					
'03	45.6		3.15	48.8		
'04		47.2	6.12	53.3	3.0	3.53% Population Growth Utah Governor's Office Planning & Budget - Aug '02
'05		48.9	9.46	58.3	3.3	" "
'06		50.6	13.21	63.8	3.8	" "
'07		52.4	17.42	69.8	4.2	" "
'08		54.2	22.12	76.4	4.7	" "
'09		56.2	27.36	83.5	5.2	" "
'10		57.1	34.24	91.3	6.9	1.68% Population Growth Utah Governor's Office Planning & Budget - Aug '02
'11		58.1	41.85	99.9	7.6	" "
'12		59.0	50.24	109.3	8.4	" "
'13		60.0	59.49	119.5	9.3	" "
'14		61.0	69.68	130.7	10.2	" "
'15		62.1	80.91	143.0	11.2	" "
'16		63.1	93.27	156.4	12.4	" "
'17		64.2	106.87	171.0	13.6	" "
'18		65.2	121.82	187.1	15.0	" "
'19		66.3	138.26	204.6	16.4	" "
'20		66.9	156.85	223.8	18.6	0.89% Population Growth Utah Governor's Office Planning & Budget - Aug '02
'21		67.5	177.23	244.8	20.4	" "
'22		68.1	199.58	267.7	22.3	" "
'23		68.7	224.07	292.8	24.5	" "
'24		69.3	250.90	320.2	26.8	" "

2.02% Average Base Load Growth (2003-2024)

9.37% Average Overall Growth (2003-2024) based on Average Projected Growth 2002-2007 Forecast

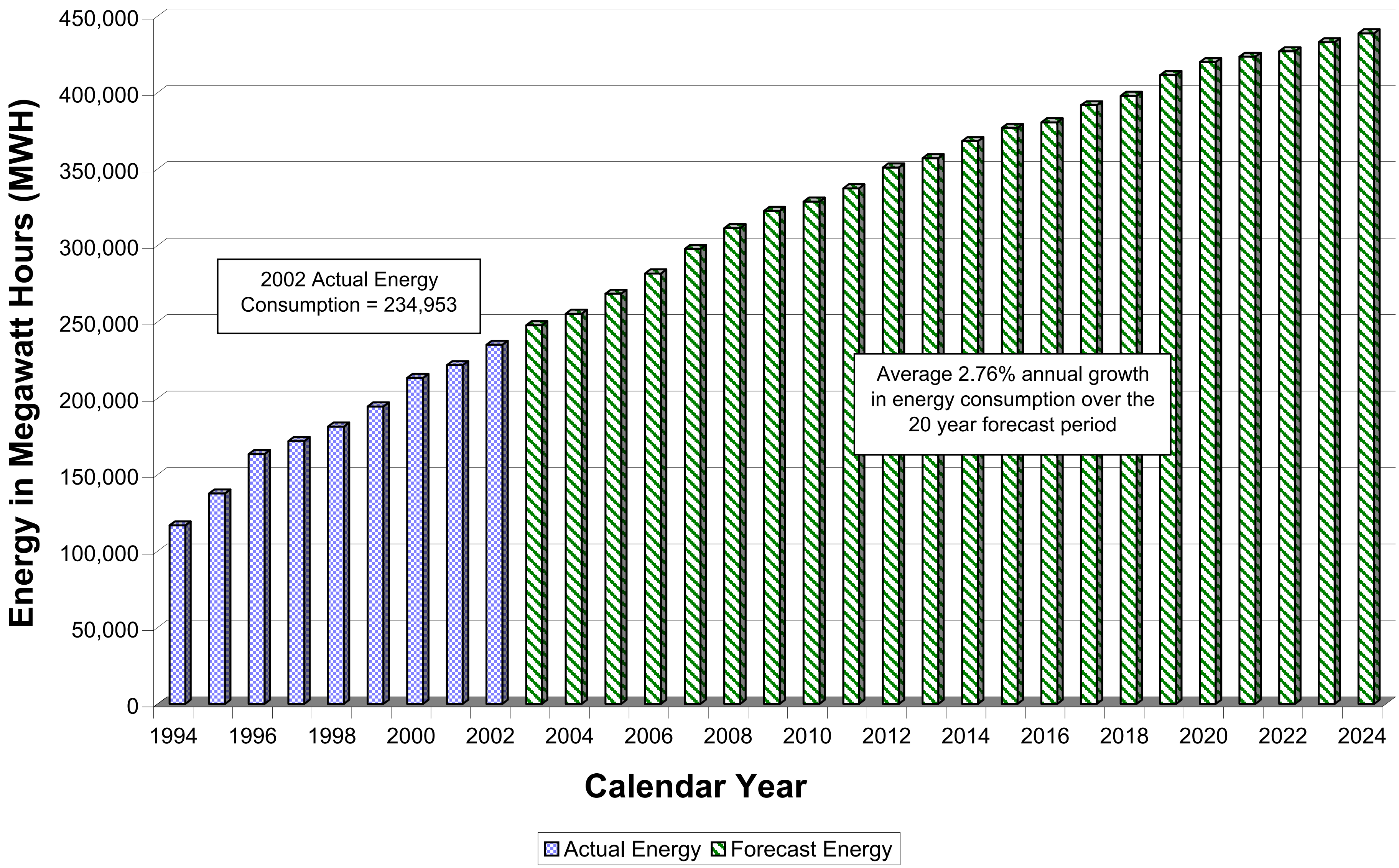
Springville City Power

20-Year Load Forecast (2004)-Base



Springville City Power

20-Year Energy Forecast - Base



SPRINGVILLE CITY POWER

20 YEAR LOAD FORECAST - BASE

May 14, 2004 - BDD-Electric Power Engineering Associates

Calendar Year	Actual Demand MW	Base Load MW	Point Load MW	Accumulated Point Load MW	Forecast Demand MW	% chg from prev.	Actual Energy MWH	Forecast Energy MWH	% chg from prev.	Actual Annual % LF	Forecast Annual % LF	% chg from prev.	Comments
1994	22.4						116,790.0			59.5			
1995	28.8					28.6	137,654.0		17.9	54.6			
1996	29.2					1.4	163,467.0		18.8	63.7			
1997	30.8					5.5	171,931.0		5.2	63.8			
1998	30.2					-1.9	181,435.0		5.5	68.6			
1999	35.2					16.6	194,605.0		7.3	63.1			
2000	40.1					13.9	213,282.0		9.6	60.7			
2001	42.1					5.0	221,618.0		3.9	60.1			
2002	44.6					5.9	234,953.0		6.0	60.2			
2003	47.2					5.8		247,702.5	5.4		59.9	-0.44	
2004		48.8			48.8	3.5 a		255,310.3	3.1		59.7	-0.44	3.53% Population Growth Utah Governor's Office Planning & Budget - Aug '02
2005		50.6	1.0	1.0	51.6	5.6		268,355.6	5.1		59.4	-0.44	" "
2006		52.4	1.0	2.0	54.4	5.4		281,595.5	4.9		59.1	-0.44	" "
2007		54.2	1.5	3.5	57.7	6.2		297,616.8	5.7		58.9	-0.44	" "
2008		56.1	1.0	4.5	60.6	5.0		311,258.2	8.4		58.6	-0.44	" "
2009		58.1	0.5	5.0	63.1	4.1		322,562.1	5.6		58.4	-0.44	" "
2010		59.1	0.5	5.5	64.6	2.3		328,645.4	4.6		58.1	-0.44	1.68% Population Growth Utah Governor's Office Planning & Budget - Aug '02
2011		60.1	1.0	6.5	66.6	3.1		337,285.0	6.8		57.8	-0.44	" "
2012		61.1	2.0	8.5	69.6	4.5		350,970.3	5.9		57.6	-0.44	" "
2013		62.1	0.5	9.0	71.1	2.2		357,079.6	4.9		57.3	-0.44	" "
2014		63.1	1.5	10.5	73.6	3.6		368,214.0	5.5		57.1	-0.44	" "
2015		64.2	1.0	11.5	75.7	2.8		376,841.1	3.3		56.8	-0.44	" "
2016		65.3	0.0	11.5	76.8	1.4		380,517.1	1.0		56.6	-0.44	" "
2017		66.4	1.5	13.0	79.4	3.4		391,643.2	2.9		56.3	-0.44	" "
2018		67.5	0.5	13.5	81.0	2.0		397,841.9	1.6		56.1	-0.44	" "
2019		68.6	2.0	15.5	84.1	3.9		411,404.8	3.4		55.8	-0.44	" "
2020		69.2	1.5	17.0	86.2	2.5		419,858.6	2.1		55.6	-0.44	0.89% Population Growth Utah Governor's Office Planning & Budget - Aug '02
2021		69.9	0.5	17.5	87.4	1.3		423,409.0	0.8		55.3	-0.44	" "
2022		70.5	0.5	18.0	88.5	1.3		426,946.1	0.8		55.1	-0.44	" "
2023		71.1	1.0	19.0	90.1	1.8		432,872.1	1.4		54.8	-0.44	" "
2024		71.7	1.0	20.0	91.7	1.8		438,764.0	1.4		54.6	-0.44	" "

2.02% Average Base Load Growth (2003-2024)
3.22% Average Overall MW Load Growth (2003-2024)
2.76% Average Overall MWh Energy Growth (2003-2024)

Assumptions:
1- Base Load escalates at the estimated population growth rate as provided by Community Development. 2004-2009 escalates at 3.53%/yr; 2010-2019 escalates at 1.68%/yr; 2020-2024 escalates at 0.89%/yr.
2- Load Factor is a tool to compare system demand and energy consumption. It has no affect on the demand forecast and so does not influence Impact Fee calculations. Annual Load Factor 2003-2024 deescalates at 0.44%/yr according to Springville City Power, based on recent downward trend apparently related to residential HVAC loads; and is based on minimum available historical load factor of 54.6 and the 2002's load factor of 60.2% with arbitrary de-escalation from 60.2% for 2002 to 54.6% in 2024; actual load factor varies greatly with the annual weather pattern.
3- Forecast Energy is calculated using Estimated Demand and Annual Load Factor.
4- Point Load Growth is based on input and forecasts from Springville City Power and historical trends.
5- "% change from previous" indicates percentage change between the prior year's value and the current year's value whether actual or forecast.
6- Historical rates of growth are: MW Demand = 8.63% , MWh Energy = 9.13% , Load Factor = 0.15% ; 1994 thru 2002 or 2003
a- 2004 reference base is 2003 Peak of 47.2 MW and 59.9% Load Factor.

Actual data by Springville City Power

SPRINGVILLE CITY POWER
20 YEAR LOAD FORECAST

May 14, 2004 - BDD, EPE Associates

Point Load Detail - Base

(in MW)

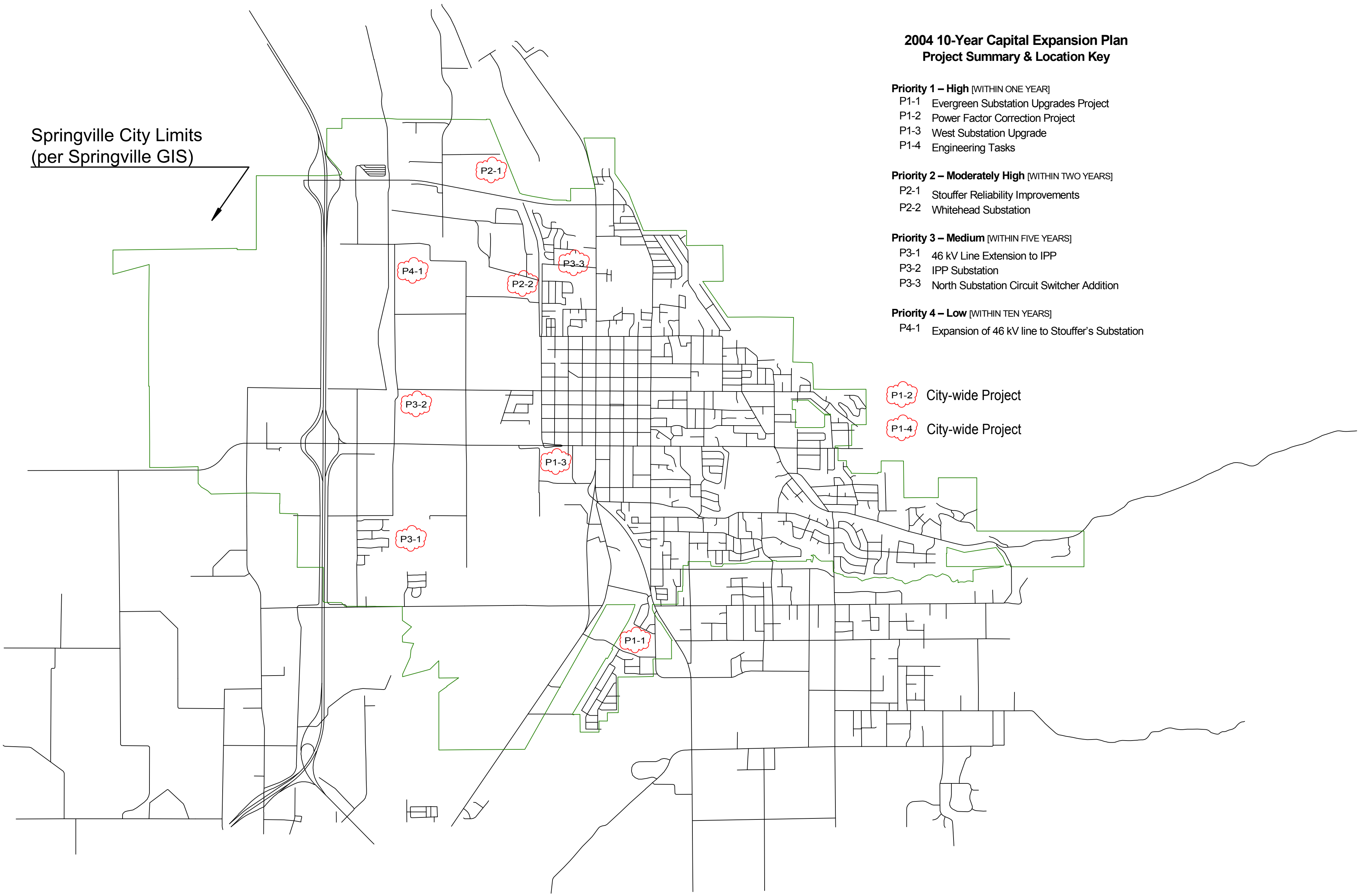
Calendar Year	West Fields	North Industrial	South City	City Center	I-15 West	North East	Hobble Creek	**Annual Total**	Calendar Year
2005		0.5					0.5	**1.0**	2005
2006	0.5					0.5		**1.0**	2006
2007			1	0.5				**1.5**	2007
2008	1							**1.0**	2008
2009		0.5						**0.5**	2009
2010	0.5							**0.5**	2010
2011			0.5	0.5				**1.0**	2011
2012	1				0.5		0.5	**2.0**	2012
2013		0.5						**0.5**	2013
2014	0.5				1			**1.5**	2014
2015			1					**1.0**	2015
2016								**0.0**	2016
2017	1	0.5						**1.5**	2017
2018					0.5			**0.5**	2018
2019			0.5	1			0.5	**2.0**	2019
2020		0.5			1			**1.5**	2020
2021	0.5							**0.5**	2021
2022					0.5			**0.5**	2022
2023			1					**1.0**	2023
2024	1							**1.0**	2024
Total	**6**	**2.5**	**4**	**2**	**3.5**	**0.5**	**1.5**	**20.0**	

APPENDIX B: Maps

Part A:

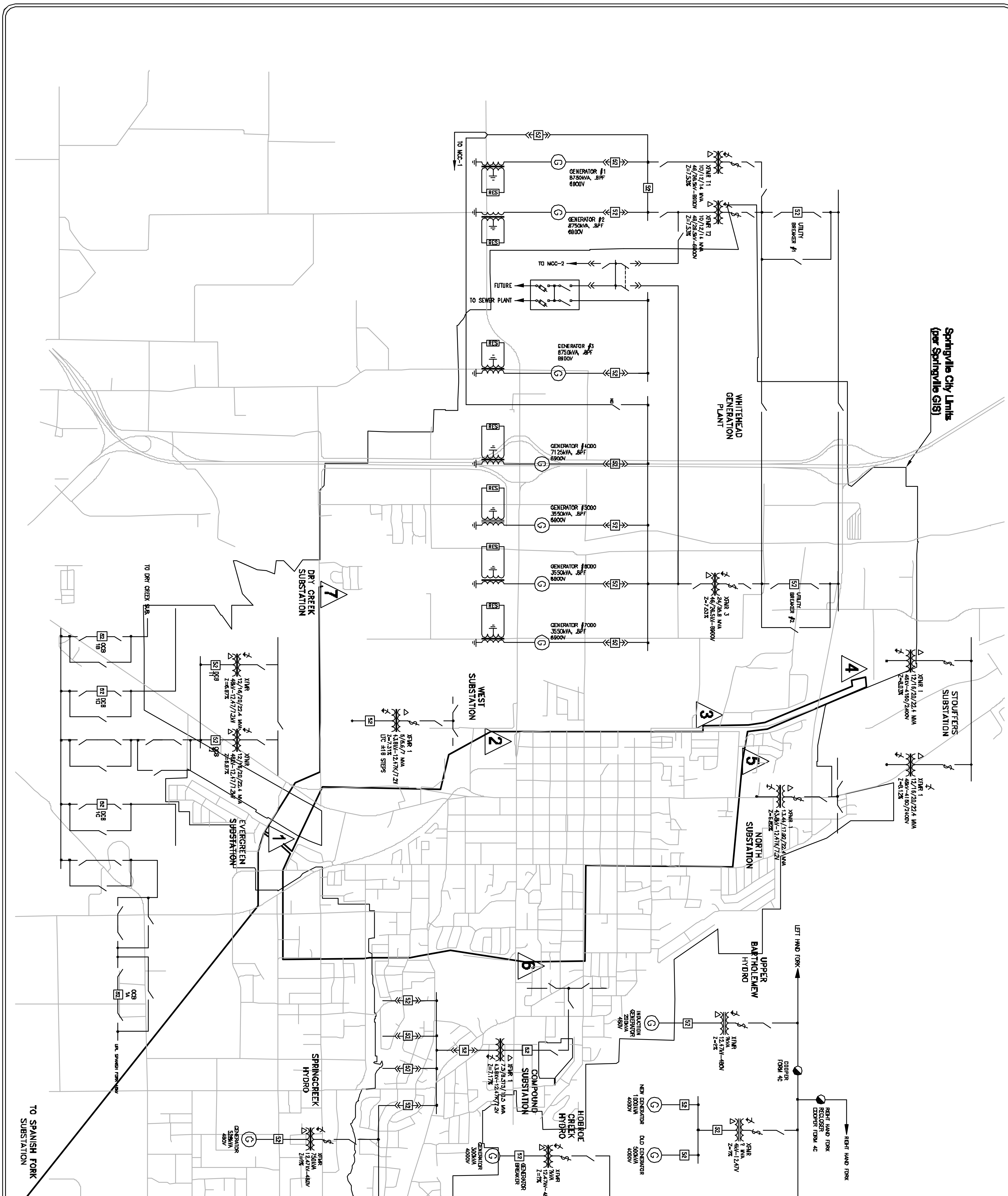
Springville City Power
<u>Ten-Year Capital Plan</u>

May 2004



Springville City Power - 2004 Ten-Year CIP Project Location Map

May 21, 2004



ENGINEERED BY	
DRAWN BY	AL
REVIEWED BY	RL
DATE	
SCALE	N/A
JOB NO.	1808

C-01

SPRINGVILLE POWER
SUBSTATION LOCATION MAP
SPRINGVILLE 46kV SYSTEM

mcF incorporated
electric power engineering
P.O. Box 1265 Arvada, CO 80001
(303) 431-7895 FAX (303) 431-1836

No.	REVISIONS	DATE

APPENDIX C: Selected Electric Utility Terms

Part A:

Springville City Power
<u>Ten-Year Capital Plan</u>

May 2004

Selected Electric Utility Terms

To assist in understanding the various technical terms which are used in the Ten-year Plan and Impact Fees discussion, the following selected, simplified terms and definitions are provided for the reader's reference:

Apparent Power (Volt Amperes – VA or KiloVolt-Ampers – **kVA**) or MegaVolt Amperes – **MVA**)	The measure of delivery capacity used to rate transformers, generators and system components. It is a direct calculation of voltage times current. For three phase systems the √3 is also included in the calculation. Apparent Power includes both real power (watts) which provides work and reactive power (volt-amps reactive – VARs) which does no work but is required to provide magnetizing current for motors and transformers. VARs are provided by generation or capacitors.
Circuit	A conductor or system of conductors through which electric current flows or is intended to flow.
Circuit Breaker (Circuit switchers are similar)	As used in substations, a device with the ability to safely disrupt or switch a high voltage flow of electrical current multiples of times. Circuit breakers include instrument transformers and protective relays which monitor system operations and automatically interrupt the circuit during improper operations or faults/short circuits.
Coincident Demand	The sum of two or more demands which occur during the same demand interval. The coincident demand for the power system is the maximum or peak demand established by all customers at the time of the power system's maximum power delivery.
Current (ampere or amps)	The measure of electrical flow in a power line. An ampere is the flow that results when the electrical pressure of one volt is applied to the resistance of one ohm in an electrical circuit.
Diversity	The ratio in % of the customer's metered coincidental demand to the system's peak demand
Energy (kilowatthours or **kWh**)	The measurement of power consumption, work or Watts over a period of time. This is typically measured by the watthour meter at the electrical service entry and is billed as kilowatthours or kWh.
Fuse	A one-time device which has a calibrated metallic link which will melt and interrupt the circuit during overloads or faults/short circuits on the power system.
Power Factor	The ratio of real power to apparent power, typically in %. Power factor is not typically billed, but if a customer's power factor is lower than specified in the rates, the utility may charge a penalty to pay for supplying the excess VARs not provided by the customer via power factor correcting capacitors.
Power or Real Power also Demand or Load (Watts – W or Kilowatt – **kW** or Megawatt - **MW**)	The actual metered demand or load provided to perform work such as run a motor, illuminate a light or to provide heat. Watts = VoltAmperes x Power Factor Watts are measured by a demand or watt meter and is billed as either demand, load or kilowatts (kW)
Substation	An combination of electrical components which provide switching, changing or regulating voltage for large amounts of electrical power.
Switch	A manual or motor operated electrical device which can open circuits with normal current flow but cannot interrupt faults or short circuits.
Transformer	A piece of electrical equipment which has the ability to raise or lower the voltage or electrical pressure of an electrical system.
Utilization	The ratio in % of a customer's demand in amperes to the rated capacity of the service main breaker rating in amperes
Voltage (volt)	The measure of electrical pressure. It is similar to the pressure in pounds per sq. inch of a water system. Voltage is the maximum effective divergence in potential between two conductors of the same circuit.

Part B:

Impact Fee Study

May 2004

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Springville is a Municipal Power City with 8,600 current customers in 2004. As a municipal power system, the “profits”, after operations and reinvestment (capital project) funding is complete, are transferred to the City General Fund to help control property tax requirements. This has proven to be very beneficial and provides a significant portion of the City’s operating funds. This local ownership and control is in contrast to an Investor Owned Utility where ultimate control is often in another state and profits are distributed as dividends to the individual investors and stock holders of the company throughout the country. The local ownership and control provides the city the opportunity to balance the diverse operational needs and requirements of its utility with the various needs and desires of its residents and other stake holders.

The dynamic nature of the electric power industry requires constant balancing of resources, customer demands, service reliability, capital improvements, stakeholder needs and sources of funding. In an ideal world, where resources and infrastructure do not need to expand to serve new load and service demands and production costs are not affected by inflation, the final cost of electric power delivered to a customer could remain relatively fixed. Typical rate structures try to account for many of the economic forces which affect the final unit cost to each customer class or category and are frequently developed using what is referred to as Cost of Service studies. The intent of such studies is to try and allocate costs of service based on the typical or average costs associated with each respective customer class. If the power utility is not experiencing increasing requirements for new levels of power related to new customers or increased costs for production of electrical power, then the average cost per unit of power would be similar to a postage stamp. For the specified service provided, everyone would pay the same rate per unit.

This is not an ideal world and as such electric power utilities face a significant challenge in balancing the dynamic changes which must be met to assure reliable, economic service delivery to its customers. In years past, all system capital expansion was funded either directly or indirectly by the rates charged for the services provided. Additional fees or special charges were not collected from those who requested new services which may have required significant investment in new facilities such as conductors, poles, transformers, substations, generation. The costs associated with these improvements were rolled in to the general service rate and everyone paid for those growth expenses related to development. When development picked up, everyone’s rates also went up to pay for service needs associated with the load growth. Over the period of the last 20 years, in an effort to implement a “pay your own way” philosophy and stabilize general rates, it has become very common place for electric utilities to charge for site specific improvements such as the installation of service conductors to the customer’s building or construction of the distribution system needed to service the various lots in new commercial or residential developments. These fees are frequently referred to as connection or hook-up fees and line extension or aid-to-construction fees, respectively. A third type of expense is also incurred by the utility due to growth related to development within its service area. These off-site improvements typically include procurement and construction expenses to cover the costs of general expansion of the power supply, the bulk power delivery transmission and distribution system and the substations required to control, regulate and deliver power to the utility’s distribution system. These costs are subject to a third classification of charges referred to as impact fees. All three of these development related fees are required to help stabilize and control base rates for all customers. Otherwise, the cost of these various growth related, both site and non-site specific improvements, would result in a need to increase the postage stamp rates paid by all customers served by the utility.

In order to address issues related to fairness and equitable application of impact fees, several specific areas of concern have been identified and were considered during the development of these fees.

- The evaluation and implementation of impact fees must be based on what is required by the Utah statutes related to impact fees.
- The impact fees must be determined using known and measurable revenue requirements related to specific capital additions.
- Projects funded by impact fee revenues must be related to system growth and be planned for completion within a reasonable length of time after the fees are collected.
- Any impact fee proposed must meet the overall goals and objectives of the City, its residents and elected officials and be politically acceptable to all stakeholders.

Impact Fee Proposal

The methodology used in developing the recommended impact fee structure is based on the concept that those who create the impact should pay a significant portion of the related costs – "pay your own way". This helps to control and mitigate potential future increases of the general service rate and provides equity and fairness to existing and new customers.

Under the Utah State Code Title 11, Chapter 36, the Impact Fees Act provides direction as to the requirements of impact fee development and application by local government. Specifically the Act requires that any impact fee must be based on growth related capital improvements to the power system as specified in the capital facilities plan. This may include existing system facilities installed to serve new and expanding loads associated with development activity. In this instance the new growth customer would "buy-into" the existing system funded by revenues collected from past and current customers.

The development of the proposed impact fee included the review and evaluation of two methods. The first provides a replacement cost or "buy-in" value for utilizing available excess capacity in the existing power system facilities. The available system capacity was evaluated and found to have been well planned and implemented, with considerable capability of supporting development growth in much of the power system's existing distribution area. The bulk power supply and delivery areas of the utility including the parts of the transmission system and some of the substations were found to be in need of significant expansion in capacity. The decision was made by Springville that the buy-in method would not be incorporated into the impact fee implementation calculations at this time. Instead, only the growth related capital additions and improvements needed by the utility since the implementation of impact fees in 1997-98 would be used to form the basis for the impact fee rate calculation. The second methodology includes the cost of capital additions identified in the 2004 Ten-Year Capital Improvements Plan budget prepared for Springville City Power and those capital addition projects completed because of growth requirements in the power system, but not included in the 1997 Impact Fees Study (Unfunded). These capital addition projects have a value of $5.4 million ($207/kVA) and $33.7 million ($787/kVA), respectively.

It is proposed that the City and Springville City Power adopt an impact fee of $425/kVA based on the results of the impact fees study. This base impact fee includes all of the 2004 Ten-Year CIP growth related project budget plus a portion of the total value of the Unfunded growth projects previously completed. This fee would then be applied to the diversified load requested by the customer. The diversity factor used to obtain the equivalent diversified base impact fee is assumed to be 65%. This diversity factor represents the variation between the customer's load at the time of peak system loading and the customer's actual metered peak load. Additionally, the typical over sizing of electrical service panels is also addressed for fairness and an assumed utilization factor of 30% is applied to all customers' service size requests. As an example, if a customer requests a 200 ampere service at 120/240 volts (48 kVA), the final impact fee would be calculated based on the capacity requirements of an equivalent 39 ampere service at the requested voltage (equivalent to 9.36 kVA), [200a x 65% x 30% x 240v]. With the differing needs of large commercial and industrial customers, these customers would pay an impact fee determined on a case-by-case basis. The final impact fee would still be based on the recommended base impact fee of $425/kVA.

A table of proposed impact fee rates for typical services is provided in Appendix D.

In this section an overview of the development of impact fees is provided and three issues will be addressed. First, why would a municipality elect to enforce an impact fee? Second, what types of projects can be funded from the revenue gained by the impact fee? Finally, what is Utah's law on the procedures that municipalities or governmental agencies should use in forming and implementing impact fee policies?

A list of selected and simplified terms and definitions used in this study has been included as Appendix C of the 2004 10-Year Capital Plan. Impact fee specific terms are also listed in the Impact fee Requirements – The Impact Fees Act section of this report.

Impact Fee Development

When identifying costs that would be associated with a new electric service, there are a number of scenarios that can be used during the development and application of impact fee policies and rates. These scenarios include, varying growth projections, differing cost recovery goals, and identifying customer groups that will pay the fee. Other alternatives may include being aware of the public's response to a sudden increase in their fees, which may effect the policies, rates, and approval of an impact fee program.

In order to assess these scenarios, several variables are taken into account. For example, there are different options on how to project the general population growth and/or commercial growth and the cost of new electric facilities associated with this growth. A less effective approach would be to project an extensive range between "best case" and "worst case" scenarios. An effective approach would be a true cost evaluation where all the projections are based on what is most likely to occur, and not what may be influenced by outside views.

In addition, there are a number of options for how to implement projecting cost recovery. The first option is a moderate approach which establishes a fee that includes the increased additional capital costs required for new electric load levels above those costs included in the standard electric rates. Such an approach would exclude any aid-to-construction or hook-up fees paid by customers requesting new levels of power delivery. This option helps to maintain reasonable electric rates by having new customers pay for the increased capital costs required by their connecting to the system and by making them buy into the existing infrastructure's available capacity at standard and equitable rates thus preserving the average cost of service rate level. The second option is a more aggressive approach which attempts to maximize the fee to the customer requesting new load by including all the increased costs associated in that request. This choice becomes appealing when the resulting fees would be low enough to gain acceptance from the public, when it would prevent electric rate increases for all customers, or when the new customers or developers are not opposed to paying a high initial electric service fee in return for lower electric service rates. The third option fosters a very pro-development approach and attempts to minimize initial electric service fees for new electrical load. Under this option, the utility or city pays for a portion of the cost of the capital improvements through available reserves. The remaining cost would be allocated into the standard electric rates, which would be paid by all customers. This option is of interest when the public would be willing to accept higher electric service rates; the existing rate structure provides adequate funding to absorb the cost of new infrastructure and new customer growth; or the overall benefits of new development and growth are greater than the negative effects of continued high rates or increasing electric rates on the general customer population.

Another variable that can greatly alter the level and type of fee and associated policies is the selection of what groups will pay the impact fee. There are two methods which can be used to separate the total customer group for impact fee purposes. First, consider residential customers, as opposed to non-residential. Residential customers have the influence of being current or future voters. In contrast, new non-residential customers influence the community by providing a tax-paying and job-providing business. Hence, balance and rationale are vital in selecting this option. Second, consider the differing geographical area within the political subdivision or utility jurisdiction. Each geographical area has existing infrastructures and growth rates which may influence the costs. These differences could justify the variation in impact fees and policies within each geographical area.

Perhaps the most crucial of all variables is the public reaction to impact fees. Existing customers may not desire an additional fee if they are planning to move within the jurisdiction. Builders have the ability to influence the business community, the economy in general and the media. If a small fee is acceptable by the community, although it may not pay off the full cost recovery, it may be a desirable alternative. These considerations as well as others that will arise as the analysis progresses will help in making a final decision. In addition, experienced consultants; city planners, engineers, and accountants; elected officials; the city's business interests; and members of the general public will help in selecting the most favorable decision.

There are various reasons why government entities may establish impact or development fees. A common reason is to obtain capital improvement funds from sources that do not include taxation or general user fees. Furthermore, impact fees at times are enforced to encourage or discourage growth in specific sectors of the population.

The economic reasoning behind impact fees is to make certain that existing customers are not required to fund a capital addition or improvement for something from which the existing customers will receive only limited or perhaps no direct benefit. For example, a municipal water system may need to build a new well to provide the needed service where residential or commercial growth will occur. However, existing customers will see no direct benefit from the new well if existing water resources are sufficient. When the costs of the new well are included in the rate base, all ratepayers will pay for the same utility services, even if the customer is not receiving benefits from the additional rate increase. In order to solve this unfairness, impact fees are implemented.

When discussing impact fees, it is imperative to identify the impact fee and any charges that result from a utility's extension cost recovery or aid-to-construction policy separately. While these two ideas are similar in that they relate to new customer growth charges or fees, they are very different in theory. An impact fee is implemented if the utility must install, construct, or purchase significant backbone system or resource additions. The revenue guarantee or contribution in aid of construction that a utility collects under most line extension policies is intended to recover excess investment that is site specific. For example, if a municipality provided water utility services to a new developed area, an impact fee may be enforced to recover the addition costs of resource development or water treatment capacity. Additionally, the municipality may implement a line extension policy for the added costs of installing a water system in the developing area. Under the line extension policy the developer will make a contribution in aid of construction (that may be refundable or non-refundable) or present a revenue guarantee. The option to install some or all of the site-specific facilities based on utility construction stipulations may be given to the builder.

Since the mid-1990s municipal power systems have expanded from the previously common procedure of only enforcing line extension policies to also using impact fees. This shift has resulted in a need for municipal power system decision makers to consider a number of diverse issues as impact fees are developed and implemented. Usually it is difficult to link a specific resource to a clearly defined, growth related activity in the electric utility industry. When developing resource plans, the overall load pattern of the system is assessed and is employed to the resource addition decision. It is also challenging to separate the benefits of a resource addition between new and existing customers due to the interrelated nature of an electric utility. For instance, if generation resources are added to meet load growth, the new generation unit is operated along with the other available resources that the utility provides. When overall operating efficiency is the objective, the utility's resources provide an economical mix, of old and new resources, which will meet the expectations of all customers. Therefore, old customers are also able to receive benefits from the new and more efficient generation resource. These issues should be considered as impact fees are developed and as the procedures for implementation of these fees are determined.

The Impact Fees Act

The legislature of the State of Utah enacted the Impact Fees Act in 1995. This act instituted procedures and requirements that local governments must follow if they desire to impose impact fees. Specific guidance is provided by the Act to aid in the analysis that must be performed for establishing proposed fees and for the accounting related requirements for expenditures and refunds of fees. The required information in accordance to the Act is as follows:

- Identification of impacts on system improvements required by development activity;
- Demonstration of the relationship between impacts and development activity;
- Estimation of proportionate share of the costs of impacts on the system that are reasonably related to new development activity;
- Description of methodology used to calculate the impact fees;
- Identification of costs of existing facilities;
- Identification of methods used to finance existing facilities;

- Identification of the extent to which newly developed properties and other properties in the community have already contributed to the cost of existing facilities by such means as user charges, special assessments, or tax revenue;
- Identification of the contribution of newly developed properties to the cost of existing facilities in the future; and
- Identification of the extent to which the newly developed properties are entitled to credits because of requirements related to contributed property that has not been imposed in other areas of the community.

The Act also distinguishes impact fees from hook-up fees and “project improvements”. Hook-up fees and “project improvements” are costs that would be implemented through connection and aid-to-construction policies, while impact fees would be implemented through system improvements. The following are the definitions of these and other key terms as included in the Act:

- "Hookup fees" mean reasonable fees, not in excess of the approximate average costs to the political subdivision, for services provided for and directly attributable to the connection to utility services, including gas, water, sewer, power or other municipal, county, or independent special district utility services.
- "Impact fee" means a payment of money imposed upon development activity as a condition of development approval. "Impact fee" does not mean a tax, a special assessment, a building permit fee, a hookup fee, a fee for project improvements, or other reasonable permit or application fee.
- "Project Improvements" mean site improvements and facilities that are:
  (i) planned and designed to provide service for development resulting from a development activity, and
  (ii) necessary for the use and convenience of the occupants or users of development resulting from a development activity.
- "System improvements" mean:
  (i) existing public facilities that are designed to provide services to service areas within the community at large, and
  (ii) future public facilities that are identified in a capital facilities plan that are intended to provide services to service areas within the community at large.
- "Development activity" means any construction or expansion of a building, structure or use, any change in use of a building or structure, or any changes in the use of land that creates additional demand and need for public facilities.

The Act outlines a precise process in order that a political subdivision may establish fees. Affected entities must review existing policies to guarantee compliance with the Act by July 1, 1997. To establish the impact fees, the municipality must adopt a capital facilities plan or include a capital facilities plan in the general plan. The plan shall include:

- Identification of demands placed on existing public facilities by new development activity;
- Identification of the proposed means by which the demands will be met;

- Consideration of all revenue sources, including impact fees, to finance the impact on system improvements;
- If a capital investment plan is developed outside the general plan, the political subdivision is required to give public notice of the plan availability, make the plan available to the public, and hold a public hearing to receive public comments at least 14 days after the plan is publicly available.

The Act requires that the municipality must develop analyses that contain the following documentation in order to implement an impact fee.

- Identification of the impact on system improvements required by the development activity;
- Demonstration of how those impacts on the system improvements are reasonably related to the development activity;
- Estimation of the proportionate share of the costs of impacts on system improvements that are reasonably related to the new development activity; and
- Identification of the methods used to calculate the impact fee.

In order to determine whether or not the proportionate share of the costs of facilities is reasonably related to the new development activity, the following must be identified:

- The cost of existing facilities;
- The manner used to finance existing facilities such as user fees, special assessments, bonds, general taxes or federal grants;
- The relative extent to which the newly developed properties and the other properties in the municipality have already contributed to the cost of existing facilities through user charges, special assessments, or general taxes;
- The relative extent to which the newly developed properties and the other properties in the municipality will contribute to the cost of existing facilities in the future;
- The extent to which the newly developed properties are entitled to a credit because the municipality is requiring the owners or developers to provide common facilities, inside or outside the proposed development that have been provided by the municipality through taxation or other means, apart from user charges, in other parts of the municipality;
- Extraordinary costs, if any, in servicing the newly developed properties; and
- The time-price differential inherent in fair comparisons of amounts paid at different times.

To endorse an impact fee, a municipality or other political subdivision must follow the procedure in the Act. The local ordinance or rule must include the following requirements:

- The impact fee cannot exceed the amount determined by following the methodology outlined above;
- The impact fee can recognize costs that will be incurred by the municipality including:
    - The construction cost of any facilities required to serve developments;

  - The cost of acquiring land, improvements, and equipment;
  - The cost of planning, surveying and engineering for work directly related to the construction of system improvements; and
  - Debt service charges if the municipality will use impact fees as a revenue stream to pay the principal and interest on bonds, notes or other obligations issued to finance the costs of system improvements.
- The municipality must hold a public hearing prior to enacting an impact fee and the proposed enactment must be available for public review for at least 14 days prior to the public hearing.

To abide by the Act, the ordinance endorsed by the municipality must include the following requirements:

- Establishment of provisions for impact fees by land use categories or areas;
- A schedule of fees for each type of development activity or a formula for determination of the fees; and
- Authorization to adjust the standard fee to recognize unusual circumstances in specific cases or if additional data become available.

The Act does not obligate, but permits the ordinance to exempt low income housing or other public purpose projects. Also, previously incurred municipal infrastructure costs that will be used by new developments or subdivisions may be recognized by the ordinance. Moreover, under specific circumstances, the impact fee may include costs sustained under a Habitat Conservation Plan related to the federal Endangered Species Act of 1973. This relates to wetlands mitigation costs, etc. related to facilities construction. If property or improvements to be provided by the developer are included in the municipality's capital improvement plan, credits against the impact fee are permitted for the value of "in-kind" donations required of the developer. These credits may consist of identification of the value of land for particular facilities such as substation sites but do not include rights of way or easements. In the impact fee, it is prohibited to include facilities that are required to alleviate deficiencies in the existing system.

As well as the above listed requirements, the Act outlines specific procedures regarding the accounting for and expenditure of funds accumulated. Funds acquired through impact fees must be tracked with care; they must be invested in interest bearing accounts; and normally they must be spent within six years of collection for approved projects or activities as identified in the impact fee capital improvement plan.

Throughout recent history the costs related to the construction of capital facilities has increased significantly. During the late 1970s and the early 1980s, there was considerable inflation compared to the relatively reasonable cost increases in the recent years. As a result of these increasing costs, the replacement or expansion of existing electric system plants is much more costly than when they were built. Hence, when facilities have available capacity there is an economic value for the originally intended customers. This value is signified as asset appreciation. Unless an additional appropriate charge is given to new customers, the economic value for existing customers diminishes as the new customer growth increases. When this occurs, current customers pay for the capacity that future customers will benefit from.

Different techniques can be used in order for the new customer to pay the increased electric capacity. New customers can pay a higher rate for service, pay for all costs dealing with becoming connected to the service, and/or pay an impact fee. Although charging different rates for service help to solve the problem, it is rarely enforced due to the complexity of allocating and administering a grandfather type of rate structure and the potential issue of pricing discrimination. By charging an impact fee, the old customer and the new customer are charged equal cost-to-serve fees. The justification in this is that the new customer is accountable for the decreased economical rent and that inflation causes the expansion of or the building of new facilities to support growth to be more costly. An impact fee allows the new customer to “buy-in” to the existing system.

To calculate the cost of impact fees, utilities generally use these guidelines:

1) Determination of the current replacement cost per unit of capacity using a Fixed Asset Evaluation. This evaluation of current depreciated replacement cost of the existing utility infrastructure is based on a combination of the following:
    a) escalating the original cost of construction to the present day by using cost adjustment factors such as those found in the Handy-Whitman Construction Cost Index;
    b) an inventory of existing facilities and estimating the cost of replacing such facilities at today's cost;
    c) reducing these replacement costs through depreciation
    d) determine asset appreciation and its associated value per kilowatt of associated available capacity for use by new or upgrading customers.
2) Utilize a multiyear capital improvement plan to provide the basis of an evaluation of the future cost of electric system additions to be implemented during a defined period of time to satisfy the capacity needs indicated by a load forecast for the same period. The associated budget provides the basis for determining the cost per kilowatt for new and increased requests for capacity.
3) Regression analysis of historical system demands and the cost of investment in plant to provide service to estimate the incremental cost of providing an additional kilowatt of capacity;

4) A regression analysis combining historic and projected costs and load requirements to provide an estimate of the increase in cost per kilowatt of capacity.

Each technique or methodology has its own advantages and disadvantages depending on the available data provided. This study utilizes the first and the second methodologies – a replacement cost evaluation and a multiyear capital improvement plan and budget. The regression analysis methods require detailed historical data on annual plant additions along with full out of pocket costs and direct contributions of labor and equipment. Historically, the department's capital projects did benefit from direct or in-house labor costs but these costs have not been tracked in detail. Therefore, regression analysis has not been used. The selected methods or techniques follow the Utah State Impact Fee Act guidelines and will be discussed later on.

System Load Growth

Springville serves about 8,600 customers. Springville is a summer peaking utility. During the summer of 2003 the peak load was about 47.2 megawatts (MW).

In order to meet demand, Springville uses a resource mix which includes city-owned fossil fuel generation, allocated participation in federal hydroelectric resources on the Colorado River, and contracted resources. Springville is a member of the Utah Association of Municipal Power Systems (UAMPS).

Springville is actively identifying and evaluating potential additions for its supply-side resource assets. The proposed Impact Fee does include allowances for the cost of the resource additions.

The 2002 load forecast for Springville that was prepared by Energy Strategies, LLC utilizes an econometric model that recognized the growth in the industrial and commercial sectors of the economy previously experienced by Springville. The 2002 forecast projected growth in peak demand would continue at or above the previous actual load growth rate of 7.74%. This is the "high" growth scenario for Springville City Power and projects at 9.37% annual growth with a peak of 130.8 MW in 2014. Due to the recent downturn in the economy a simplified, more conservative base load forecast has been prepared as part of this study at Springville City Power's request.

The "base" load forecast that was prepared by Electric Power Engineering Associates indicates that Springville's normal energy and peak demand without any "point load" growth are projected to grow at an average annual compound rate of about 2.0 percent resulting in a 2014 peak demand of 63.1MW. This normal load growth is based on the 20-year population growth projections provided by the Utah Governor's Office of Planning and Budget in August 2002. With the addition of projected development (point load) in selected areas of the city, as provided by Springville personnel, to the normal load growth, this most likely base growth scenario forecasts a 3.22% average load growth with a forecast peak demand of 73.6MW in 2014.

System Capital Additions

An annually updated Five-Year Capital Improvement Plan (CIP) is provided by Springville City Power for capital budgeting and planning purposes. Specific projects are listed that will assist in providing capacity for load growth and improving reliability in those portions of the power system which directly or indirectly benefit all Springville City Power customers. The current Springville City Power CIP Plan's budget totals through FY2004 equal $5.6 million from the original 1997 10-Year Plan plus $34.1 million in additions and $3.2 million in deletions for a total of $36.5 million through 2004. A 10-Year Capital Improvement Plan has been developed by Electric Power Engineering Associates as a part of this impact fee study. The Department staff studied and reviewed the CIP Plan and budget to assist the engineer to identify and verify projects necessary for system growth. A few CIP projects, such as SCADA system improvements are growth-related, but are not included in the report since they would likely have been considered absent of any growth and will grant long-term, system-wide benefits. Project budgets included in this new impact fees study are related to power supply, transmission, and substation expansion or upgrade due to load growth. In order to meet forecast load growth, the following projects have been selected to increase the electric system capacity.

The 1997 10-Year Capital Improvement Plan identified various transmission and substation projects anticipated as needed to support forecast growth. This 1997 Plan included the following applicable projects:

Project	Estimated Cost
West Transmission Loop: Nestle to Industrial Park North Substation......	$300,000
Industrial Park North Substation (Part of Combined '99-'00 CIP Budget).............	$700,000
West Transmission Loop: Industrial Park to 4800 & Evergreen…………	$900,000
4800 South Substation..………………………………………………………..	$1,800,000
IPP West Substation…………………………………………………………	$2,700,000
Compound Substation………………………………………………………..	$700,000
TOTAL 1997 10-Year CIP (Transmission and Substation Only)	$7,100,000

The following distribution projects were included in the 1997 10-Year Capital Improvement Plan, but are not part of the Impact Fee Analysis since they relate to distribution improvements only.

2000 Upgrade feeders in Industrial Park (Part of Combined '99-'00 CIP Budget)..	$700,000
4 kV to 12 kV Conversion (completed at a cost of $791,796)...........................…..	$800,000
TOTAL 1997 Distribution CIP (Not Included in Impact Fees)	$1,500,000

With the project work priorities identified through 2003; the following projects were purposely delayed to a later date and as a result their estimated budgets have been dropped from the prior CIP Plan.

Industrial Park North Substation..	$700,000
4800 South Substation..	$1,800,000
2000 Upgrade feeders in Industrial Park..	$700,000
TOTAL Delayed or Deleted Projects	$3,200,000

The dynamic changes in ongoing electric operations through 2003 required that the following projects and budgets be added to the impact fee related project list but were "unfunded" [Not included in the 1997 Impact Fee calculation].

WHPP Expansion…………………...	$4,200,000
2004 Evergreen Distribution Substation Upgrade..................................	$2,000,000
SUVPS-UPL Spanish Fork Substation Upgrade…………………..........	$350,000
Dry Creek Transmission Substation...	$2,200,000
Nebo Power Station...	$25,350,000
TOTAL CIP Not Included in 1997 Plan ("unfunded")	$34,100,000

The following capacity related CIP projects have been completed:

	Actual Expenditures
West Transmission Loop: Industrial Park to 4800 & Evergreen…….......	$161,772
Dry Creek Substation...	$2,158,665
Compound Substation...	$475,000
Whitehead Power Plant...	$4,197,018
2000 Evergreen Upgrade......………………………………………..........	$1,873,297
SUVPS-UPL Spanish Fork…………………………………....................	$355,052
TOTAL Expended 1997 – 2003 for CIP Expansion	$9,220,804

The total impact fee revenues since 1998 have been $1,203,224.86. The net difference between total expenditures and total revenues related to impact fees equals $7,867,579.14.

2004 10-Year Capital Improvement Project Plan

The projected growth related capital improvement projects for the next ten years as included in the Plan and projects carried forward from the 1997 10-Year CIP Plan are indicated below:

Priority 1 – High	Growth Related Budget Estimates
Evergreen Substation Upgrades Project..	$180,000
Power Factor Correction Project..	$120,000
West Substation Upgrade...	$705,000
Engineering Tasks..	$0
TOTAL - Priority 1	$1,005,000
Priority 2 – Moderately High	
Stouffer Reliability Improvements...	$132,000
Whitehead Substation..	$240,000
TOTAL - Priority 2	$372,000

<u>Priority 3 – Medium</u>	
46 kV Line Extension to IPP..	$440,000
IPP Substation..	$1,250,000
North Substation Circuit Switcher Addition...	<u>$22,500</u>
TOTAL - Priority 3	$1,712,500
<u>Priority 4 – Low</u>	
Expansion of 46 kV Line to Stouffer's Substation..................................	<u>$2,263,000</u>
TOTAL - Priority 4	$2,263,000

The 2004 10-Year CIP Project Plan includes a combined capital additions budget requirement of $5,365,000. Through the State Impact Fees Act, engineering and related costs associated with implementing policies in conformity with the Act may be collected through impact fees. These costs are approximately $29,200. Hence, the total costs to be collected as part of the impact fees are calculated to be **$5,394,200**.

When determining the suitable impact fee methodology, it is important to remember that there is no right or wrong methodology. The important factors are that the method is reasonable, meets the objectives of Springville, and is legal under the Act.

In establishing a potential dollar value for the impact fee, an acceptable measurement unit must be recognized. For instance, if the number of customers served is the basis for construction of new system plant additions, the measurement base would be the number of customers. For backbone system additions, capacity requirements are the basis for infrastructure expansion therefore demand in kVA (kilovolt-amperes) would be the measurement base.

Replacement Cost Methodology

Impact fees usually render some type of compensation to current ratepayers for the available system capacity used by new customers. This is the basis of the Replacement Cost methodology. The formula used to calculate this “buy-in” rate is quite simple, although accumulating the necessary data can sometimes be a challenge. The buy-in value is derived by taking the replacement value of the existing system to be included in the rate less the original book value included in the cost of service rates charged to all customers and then dividing it by the selected unit of load (e.g., kilowatt demand or kilovolt-ampere capacity) currently being used by the system. This method was reviewed and the available overall system capacity was evaluated and found to have been generally well planned and implemented in prior years. The original book value for the existing system improvements in this method is $35,962,212. Future ratepayers along with existing customers will pay on this level of existing debt services so the value of the original debt is assumed to be excluded from any buy-in methodology. This assumption is verified through the annual debt service summary-repayment schedule which shows that $2.4 million of current revenue requirements are applied to debt services related to most prior generation additions and electric system growth related capital expansion.

The evaluation of the existing system has indicated that there is existing capability of supporting various levels of development growth in much of the power system’s existing distribution area. However, the bulk power supply and delivery areas of the utility including parts of the transmission system and some of the substations were found to be in need of significant expansion in capacity. The decision was made by Springville that the buy-in method would not be incorporated into the impact fee implementation calculations at this time. Instead, the systems additions methodology would be used and incorporate the values of previously completed qualified growth related projects which were not included in the 1997 calculation of the Springville City Power Impact Fees. This is similar to a buy-in but since the projects are well identified and can be linked to overall system growth requirements, they are included not as existing infrastructure requiring proportioning and replacement evaluation, but as a systems addition designated as “Unfunded”.

System Additions Methodology

The system additions methodology used for determination of unit impact fee costs for capital growth projects in Springville City Power's service area includes two components. Both are discussed below.

In the discussion of systems capital additions above, the 2004 CIP budget for growth-related projects for the next 10 years and cost establishment for impact fees was identified as being $5,394,200. The base and high scenario load forecasts project Springville's load will grow between 74MW-130MW by the year 2014 or an increase of up to 83MW compared to the current peak. This systems additions methodology yields a potential gross impact fee in the range of $65.78 to $207.47 per kVA, depending on the growth scenario employed for future projects over the next 10 years.

Utilizing the systems addition methodology to determine the impact fee related to future CIP Budgets has the distinct benefit of being relatively easy to determine and adjust as system requirements change. One of its major drawbacks is that it is very sensitive to load growth projections as shown in the calculation above. Another point of concern is that the CIP payback period related to the impact fee selected can also vary greatly depending upon where the impact fee lies within the range identified.

A second component is the cost of recently completed projects required to serve new development related load growth but not included in the prior 1997 impact fees study. These "Unfunded" projects are itemized in the system capital additions section and unaudited expenditures total $33,700,052. The net added system capacity available to the customers of Springville City Power due to these projects is 42.82 MWA with an equivalent value per unit of available capacity of $787 per kVA.

Combined, these two system additions methodology components result in a full or maximum per unit cost ranging from $853 to $994 per kVA of system capacity utilized by new customer growth related load or demand.

It is recommended that the Department adopt a base impact fee of $425/kVA of system load based on the outcomes of the replacement and system addition methodologies evaluated. This amount will fund the 2004 CIP Plan's Projects identified above plus partially reimburse (approximately 27%) the costs not yet recovered for previously completed qualified but "unfunded" projects during the 10 year life of this study. The City has determined that this base $425 impact fee rate should be assessed on all new loads requested of the electrical utility. It is to be equitably and fairly charged to all customers requesting either new service capacity or increased service capacity wherever they are within the municipal electric utility service area.

The estimated diversified load of the customer would be applied to applicable impact fee charge. Assuming that the customer's load at the time of the system peak is 65% of their actual peak load as measured at the customer's meter, this equates to a 65% diversity and reduces their requested service capacity by the same amount for use in calculating their final impact fee charges. A second multiplier "utilization factor" is applied to account for the difference between the installed service size requested by a customer and the estimated demand or load required by the customer. This utilization factor has been reviewed by Springville and has been determined to be 30%. The impact fee for all electrical services would be based on a combination of a diversity of 65% and 30% utilization of the service size. As an example, if a customer requests a 200 ampere service at 120/240 volts (48 kVA), the final impact fee would be calculated based on the capacity requirements of an equivalent 39 ampere service at the requested voltage (equivalent to 9.36 kVA), [200a x 65% x 30% x 240v]. With the differing needs of large commercial and industrial customers, these customers would pay an impact fee determined on a case-by-case basis. The final impact fee would still be based on the recommended base impact fee of $425/kVA.

An impact fee schedule with a selection of typical service requests is listed in Appendix A.

Electric Power Engineering Associates has relied upon cost data and other information provided by Springville City Power during the preparation of this report and its supporting work product. While we have no reason to believe that the information provided to us, and upon which we have relied, is inaccurate in any material respect, we have not verified independently such information and cannot guarantee its completeness or accuracy. Electric Power Engineering Associates reserves and retains all rights to this work product but licenses Springville City Power to use the work product in its normal activities.

Review of Existing Impact Fees

Springville City Ordinance 4-98 provides for the payment of a varying impact fee based loosely on $13 per kVA by the owner/builder of a facility seeking electrical service from the Springville City Power. The actual fee charged varies from $500 for a 100-200a residential building to $20,000 for a commercial account with loads between 1000 and 1500 kVA. This fee is in addition to other processing fees, connection fees or cost recovery (aid-to-construction) fees that are required under other Springville City Ordinances. Based on a review of the Utah Code and the methodology of the calculation of the current fee, the fee is essentially in compliance with the Impact Fees Act, but in need of updating of fee calculation, allocation methodology and provisions for adjusting the standard fee to recognize unusual circumstances or if additional information becomes available as required in Section 11-36-202.2c

Capital Improvement Plan

Springville City Power prepares a five year plan for capital improvements on an annual basis that provides budgets and descriptions for the proposed projects and the justification for the investment. This budget is approved by the City Council. Springville City also develops a Capital Improvement Fund Forecast that identifies the sources of revenue for the projected investments. These sources of revenue include interest income, impact fees, hook-up fees, aid-to-construction fees, and current revenues from sales. This capital improvement plan meets the requirements of Section 11-36-201.

The 2004 Ten-Year Capital Improvement Plan identifies $5,731,700 of new capital investment of which $5,394,200 has been identified as growth related through the period ending FY2014. These budgeted generation, transmission and substation projects are required to provide additional capacity to meet growth, related to development activity within the utility's service area. These investments would not be required to serve the existing customer base. System additions and improvements that will benefit existing ratepayers by only providing more reliable service or improving the efficiency of the operations of the transmission and distribution systems have been excluded from the revenues to be collected through the impact fee.

Methodology Used to Calculate Impact Fee

Springville City Power in conjunction with their engineer has proposed an impact fee calculation methodology that embraces a system additions approach. An evaluation of a replacement cost methodology was reviewed and a decision was made by the City to only include the systems additions approach. The systems additions include both the cost of future qualified growth projects and qualified projects which were not part of the 1997 impact fees study, but which were completed after 1997. This methodology has been applied to the supply resources, transmission and distribution substations.

Identification of Cost of Existing System

The current net value (current adjusted plant value less original book value) of plant investment for the generation, transmission and distribution plant is $72,087,756 based on the 2004 Fixed Asset Evaluation and data found in the Springville City Annual Financial Report dated June 30, 2003. This amounts to an investment of approximately $1,528 per kilowatt of 2003 system peak demand. However, these investment averages may be overstated since labor costs have not always been capitalized when investments in plant were booked so original labor costs may not have been deducted from current plant values.

Methods Used to Finance Existing Facilities

Springville City Power's Capital Improvement Program is presently funded through current revenues, interest income, impact fees, and various contributions in aid of construction. The Utility has also funded generation asset acquisition and electric system expansion through bond proceeds. According to latest available audit (June 30, 2003), the outstanding bonds total approximately $11.9 million.

Identification of Contributions to System Additions From Other Sources

Springville City Power is operated as a separate fund from other city funds. It has received a $3.681 million loan from other non-Department funds. These funds were used for general operations, not capital additions. Other general types of fees collected include miscellaneous fees for services rendered, hook-up fees and aid-to-construction fees for development projects, i.e., site improvements, and this practice will be continued.

Identification of the Contribution to the Cost of Existing Facilities By Newly Developed Properties in the Future

A postage stamp type of rate is applied to each class of customer by Springville City Power. All ratepayers both current and future ratepayers will be served at the same postage stamp rate. Annual debt service is included in the revenue requirements that will be recovered through the postage stamp rate. Through 2009 the general ratepayer revenues will fund the annual debt service of about $2.4 million or an estimated $0.0096 per kilowatt/hour sold. Under the Impact Fee Methodology used to develop the impact fee rate, the debt service related contribution to existing plant investment is recognized as a "credit" against the replacement value. “Unfunded” capital expansion projects which have been completed but were not included in the original 1997 impact fee calculation will be partially funded through future impact fee collections. The impact fee will be assessed of all new capacity requests.

Identification of the Extent to which Newly Developed Properties are Entitled to a Credit Because of Contributed Property Requirements Not Imposed Elsewhere

Because of the Springville City Power's policies regarding contributed property for on-site or project improvements, newly developed properties have been treated and will continue to be treated on an equitable basis with previous development activity. The impact fees will only be based on calculations that recognize growth-related backbone system improvements and the replacement plant methodologies. Developers, builders and customers seeking service from Springville will continue to provide easements and rights of way for electric power facilities at no cost to the Utility.

Appendices Notes

Part A: Springville City Power
Ten-Year Capital Plan; May 2004

The following Appendices are located immediately after the narrative of Part A - Ten-Year Capital Plan between pages 20 and 21 of the report.

Appendix A: Load Study Detail

The following charts, tables and data are included in Appendix A –

1. “20-Year Load Forecast (2002) – High” contained in [SCP-'04 20YearLoads(High).xls]
    a. Chart-20 year forecast
    b. Table: 20_Year_Load
    c. Table: Loadcast_Graph
2. “20-Year Load Forecast (2004) – Base” contained in [SCP-'04 20YearLoads(Base).xls]
    a. Chart-20 Year Load MW
    b. Chart-20 Year Energy
    c. Table: 20_Year_Load
    d. Table: Point_Load

Appendix B: Maps

The following Maps are included in Appendix B –

1. “Springville City Power – 2004 Ten-Year CIP Project Location Map” contained in [SPRINGVILLE_10-yr CIP Location .pdf]
2. “Springville Power – Substation Location Map; Springville 46kV System” contained in [Springville Substation Map.pdf]

Appendix C: Selected Electric Utility Terms

The following Document is included in Appendix C –

1. “Selected Electric Utility Terms” contained in [APPENDIX C.Terms & Definitions.doc]

Appendices Notes - Continued

Part B: Springville City Power
<u>Impact Fee Study</u>; May 2004

The following Appendices are located immediately after the narrative of Part B – <u>Impact Fee Study</u> behind page 40 of the report.

Appendix D: Impact Fee Schedule

The following charts, tables and data are included in Appendix D –

1. "2004 Impact Fee Calculation Worksheet" contained in [2004 Impact Fee Worksheet.040531.pdf]
   a. Table: Impact Fee Calc $425,30%
   b. *Note*: The Workbook [2004 Impact Fee Worksheet.040531.xls] includes worksheets which can and should be used to calculate the Impact Fee to be charged for new or expanded services.
      i. This workbook also contains the following worksheets:
         1. "Impact Fee Calc $425,30% & Hobb" (which was not adopted as part of the 2004 Impact Fee Study but includes a cost adder for extra costs related to anticipated near term infrastructure expansion to serve future increased load of non-Springville Residents in Hobble Creek Canyon.
         2. "Large Impact Fee Calc Compare" which can be used to compare the cost to large customers for various methods of assessing Impact Fees for new or expanded services.
2. "Master Input & Summary" contained in [Master Input & Calc Summary Sheet.May '04.pdf]
   a. Table: $425 Base Fee
   b. *Note*: The Workbook [Master Input & Calc Summary Sheet.May '04.xls] also includes Worksheet "$425 Base Fee & Hobble Creek" which provides the cost basis for the reviewed but unadopted Impact Fee cost adder for Canyon customers.

Appendix D: Impact Fee Schedule

Part B:

Springville City Power
<u>Impact Fee Study</u>

May 2004

SPRINGVILLE CITY POWER
2004 IMPACT FEE CALCULATION WORKSHEET
May 2004

An Electrical Service Impact Fee is required for all new and expanded electrical services according to:

Springville City Ordinance [Proposed]

(a) The impact fee shall be charged for all new service connections where no existing electrical service has been provided by the Department or whenever a customer desires to increase the size of an existing electrical service. In the latter instance, the impact fee shall be based on the difference in service capacity, as estimated by the Department, between the new and existing service. The impact fee shall be charged throughout the Springville service territory for all classes of service.

(b) The impact fee shall be based on a formula that recognizes the cost of system improvements and the gain in system capacity and will be available for review at the Department's offices during regular business hours. The fee and formula will be reviewed on an annual basis and will be adjusted to ensure that the fee is imposed fairly. The fee may also be adjusted to reflect unusual circumstances based on recommendations of the City Administration and approved by the City Council. The impact fee may also be adjusted for a particular development based on studies or data provided by a developer after review by the Department and approval by the City Administration and City Council.

The impact fee for all new or expanded electrical services shall be in accordance with the following worksheet. New services are based on panel breaker size and voltage rating; expanded services are based on the differential current (new minus the existing main breaker size and the voltage rating.

Calculate or enter service size:

Amperage:	100.00	Main breaker size or differential current for upgrades
Voltage (in volts):	240	
Single (1) or three (3) phase:	1.00	
New kVA/KW Service:	24.00	

Calculate Impact Fee:

Estimated Non-diversified Demand With Utilization:	7.20
Impact Fee:	$1,987.20

Impact Fee Base =	$425.00	Per kVA of system capacity
Diversity Factor =	65%	Non-coincidental Peak vs. System Peak Demand
Diversified Base Fee =	$276.00	Per kVA of Estimated Diversified Capacity
Utilization Factor =	30%	Actual Demand vs. Installed Service Capacity (Multiplier applied to requested service size.)
Applied Fee =	$82.80	Per kVA of customer requested service increase. Single phase KVA is based on main breaker ampere size x normal line-to-line voltage; ie 100a x 240v = 24kVA; Three phase KVA requires a multiplier of 1.732

Impact Fee Table:

REQUESTED SERVICE SIZE [AMPERAGE LESS THAN OR EQUAL TO]	VOLTAGE 120/240 1 PHASE	120/208 3 PHASE	277/480 3 PHASE
10	$199	$298	$688
20	$397	$597	$1,377
30	$596	$895	$2,065
40	$795	$1,193	$2,754
50	$994	$1,492	$3,442
60	$1,192	$1,790	$4,130
70	$1,391	$2,088	$4,819
80	$1,590	$2,386	$5,507
90	$1,788	$2,685	$6,195
100	$1,987	$2,983	$6,884
125	$2,484	$3,729	$8,605
150	$2,981	$4,475	$10,326
175	$3,478	$5,220	$12,047
200	$3,974	$5,966	$13,768
300	$5,962	$8,949	$20,652
400	$7,949	$11,932	$27,535
500	$9,936	$14,915	$34,419
600	$11,923	$17,898	$41,303
700	$13,910	$20,881	$48,187
800	$15,898	$23,864	$55,071
900	$17,885	$26,847	$61,955
1000	$19,872	$29,830	$68,839
1100		$32,813	$75,722
1200		$35,796	$82,606
1300		$38,779	$89,490
1400		$41,762	$96,374
1500		$44,745	$103,258
1600		$47,728	$110,142
1700		$50,711	$117,026
1800		$53,694	$123,910
1900		$56,677	$130,793
2000		$59,660	$137,677
2500		$74,575	$172,097
3000		$89,490	$206,516

SPRINGVILLE CITY POWER

2004 IMPACT FEE CALCULATION WORKSHEET

with Hobble Creek Special Impact Fee

May 2004

An Electrical Service Impact Fee is required for all new and expanded electrical services according to:

Springville City Ordinance [Proposed]

(a) The impact fee shall be charged for all new service connections where no existing electrical service has been provided by the Department or whenever a customer desires to increase the size of an existing electrical service In the latter instance, the impact fee shall be based on the difference in service capacity, as estimated by the Department, between the new and existing service The impact fee shall be charged throughout the Springville service territory for all classes of service.

(b) The impact fee shall be based on a formula that recognizes the cost of system improvements and the gain in system capacity and will be available for review at the Department's offices during regular business hours. The fee and formula will be reviewed on an annual basis and will be adjusted to ensure that the fee is imposed fairly The fee may also be adjusted to reflect unusual circumstances based on recommendations of the City Administration and approved by the City Council The impact fee may also be adjusted for a particular development based on studies or data provided by a developer after review by the Department and approval by the City Administration and City Council

The impact fee for all new or expanded electrical services shall be in accordance with the following worksheet New services are based on panel breaker size and voltage rating, expanded services are based on the differential current (new minus the existi

Calculate or enter service size:

Amperage:	100.00	Main breaker size or differential current for upgrades
Voltage (in volts):	240	
Single (1) or three (3) phase	1.00	
New kVA/KW Service.	24.00	

Calculate Impact Fee:

Estimated Non-diversified Demand With Utilization	7 20
Impact Fee:	$2,736.00

Impact Fee Base =	$584.00	Per kVA of system capacity
Diversity Factor =	65%	Non-coincidental Peak vs. System Peak Demand
Diversified Base Fee =	$380.00	Per kVA of Estimated Diversified Capacity
Utilization Factor =	30%	Actual Demand vs. Installed Service Capacity (Multiplier applied to requested service size.)
Applied Fee =	$114.00	Per kVA of customer requested service increase. Single phase KVA is based on main breaker ampere size x normal line-to-line voltage, ie 100a x 240v = 24kVA, Three phase KVA requires a multiplier of 1 732

Impact Fee Table:

REQUESTED SERVICE SIZE [AMPERAGE LESS THAN OR EQUAL TO]	VOLTAGE 120/240 1 PHASE	120/208 3 PHASE	277/480 3 PHASE
10	$274	$411	$948
20	$547	$821	$1,896
30	$821	$1,232	$2,843
40	$1,094	$1,643	$3,791
50	$1,368	$2,054	$4,739
60	$1,642	$2,464	$5,687
70	$1,915	$2,875	$6,634
80	$2,189	$3,286	$7,582
90	$2,462	$3,696	$8,530
100	$2,736	$4,107	$9,478
125	$3,420	$5,134	$11,847
150	$4,104	$6,161	$14,217
175	$4,788	$7,187	$16,586
200	$5,472	$8,214	$18,956
300	$8,208	$12,321	$28,433
400	$10,944	$16,428	$37,911
500	$13,680	$20,535	$47,389
600	$16,416	$24,642	$56,867
700	$19,152	$28,749	$56,344
800	$21,888	$32,856	$75,822
900	$24,624	$36,963	$85,300
1000	$27,360	$41,070	$94,778
1100		$45,177	$104,256
1200		$49,284	$113,733
1300		$53,392	$123,211
1400		$57,499	$132,689
1500		$61,606	$142,167
1600		$65,713	$151,645
1700		$69,820	$161,122
1800		$73,927	$170,600
1900		$78,034	$180,078
2000		$82,141	$189,556
2500		$102,676	$236,945
3000		$123,211	$284,333

SPRINGVILLE CITY POWER
IMPACT FEE STUDY
MASTER INPUT & SUMMARY
May 2004

A. Impact Fee Base Calculation

1- System Capital Additions ('04 10-Year CIP Plan)

a) Project List and Budget [Capacity Additions Only]

Priority 1- High	% for Growth	Total	Apportioned
Evergreen Substation Upgrade =	100%	$180,000	$180,000
Power Factor Correction =	100%	$120,000	$120,000
West Substation Upgrade =	100%	$705,000	$705,000
Engineering Tasks =	0%	$137,000	$0
Total Priority 1:		$1,142,000	**$1,005,000**

Priority 2 – Moderately High	% for Growth	Total	Apportioned
Stouffer Reliability Improvements=	60%	$220,000	$132,000
Whitehead Substation=	80%	$300,000	$240,000
Total Priority 2		$520,000	**$372,000**

Priority 3 - Medium	% for Growth	Total	Apportioned
46 kV Line Extension to IPP=	100%	$440,000	$440,000
IPP Substation=	100%	$1,250,000	$1,250,000
North Substation Circuit Switcher Addition=	30%	$75,000	$22,500
Total Priority 3		$1,765,000	**$1,712,500**

Priority 4 - Low	% for Growth	Total	Apportioned
Expansion of 46 kV line to Stouffer's substation=	100%	$2,275,500	$2,275,500
Total Priority 4			**$2,275,500**

2004 Impact Fees Study **$29,200**

TOTAL CAPITAL ADDITIONS FOR PRIORITY GROUPS 1, 2, 3,4 & Study: **$5,394,200** $5,731,700 Total Unapportioned

b) Springville 10-Year Load Forecast:

Current Peak =	48	MW	
Base Forecast =	74	MW	26 MW Net "Base" Load Growth to 2014
High Forecast =	130	MW	82 MW Net "High" Load Growth to 2014

c) '04 CIP Systems Additions Impact Fee Based on Increased Demand for the 10-Year Load Forecast:

Base =	$207.47	/kW or kVA
High =	$65.78	/kW or kVA

2- Systems Capital Additions (Unfunded)

a) Unfunded Capital Additions Project List and Budget (these are projects identified, budgeted and constructed after the 1997 Impact Fee adoption)

WHPP Expansion=	$4,197,018	
Evergreen Substation Upgrade=	$1,873,297	
SUVPS Spanish Fork UP&L Substation Upgrade=	$355,052	
Dry Creek Transmission Substation=	$2,158,665	
NEBO Power Station=	$25,116,020	Not yet included in Booked Capital Probjects amounts
Net Book Value:		**$33,700,052** (All projects are due to system load growth & identified after the 1997 Impact CIP Plan was developed)
Added System Capacity (kVA)...................................	42,820	(90 MVA with Evergreen Upgrade - 2003 System Peak 47.2 MW)
Impact Fee due to Unfunded CIP Additions=	$787.02	/kW or kVA

3- Net Carry Forward of Historical Impact Fee Revenues/Expenses

Projected Impact Fee Balance FY04 = ($7,867,579.14)

4- Impact Fee Base Determination

Impact Fee Base (100% '04 10-Year & 27% Unfunded)=	**$425.00**
Diversity Factor =	65%
Diversified Base Fee=	$276.00
Utilization Factor=	30%
Applied Impact Fee=	$82.80

To determine the final Impact Fee Rate in $/kVA, the Impact Fee Base is multiplied by the Diversity Factor which represents the variation between the customer's load at the time of peak system loading and the customer's actual metered peak load. The result is the Diversified Base Fee which is then multiplied by the Utilization Factor. This provides the "Applied Impact Fee" which is multiplied by the requested service size in kVA to determine the total final fee amount to be charged.

Final Fee = main breaker size X line to line voltage X 1 (or 1.732 for 3 phase) X Applied Impact Fee

The Utilization Factor attempts to equate actual customer load demand in kW to the installed main breaker and voltage rating in kVA. The actual Utilization Factor varies widely depending upon the type of customer. The 30% value for the Utilization Factor was determined by evaluating historical load characteristics and economics. At 30% utilization the average 100a, 240v residential service equates to an assumed usage of 4.684 kVA and a final Impact Fee assessment of $1,987.