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February 1, 2007

RECEIVED

FEB 02 2007

PUBLIC SERVICE COMMISSION

Via Federal Express

Ms. Elizabeth O'Donnell
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: The Application of Big Rivers Electric Corporation for Approval of an Interconnection Agreement with Kentucky Utilities

Dear Ms. O'Donnell: Case No. 2007-00058

Enclosed for filing are an original and ten copies of the application of Big Rivers Electric Corporation for approval of an interconnection agreement with Kentucky Utilities. A copy of this application has been sent to Kentucky Utilities. Please give me a call if you have any questions.

Sincerely,

Tyson Kamuf

TAK/ej

Enclosures

Telephone (270) 926-4000
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100 St. Ann Building
PO Box 727
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42302-0727

RECEIVED

FEB 02 2007

PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:

The Application of Big Rivers Electric Corporation for Approval of an Interconnection Agreement with Kentucky Utilities

Case No. 2007-00058

APPLICATION

Big Rivers Electric Corporation ("Big Rivers") files this application ("Application") seeking (1) approval of an interconnection agreement ("Interconnection Agreement") between Big Rivers and Kentucky Utilities ("KU") that supersedes an earlier agreement, and that calls for an additional 345 kilovolt ("kV") interconnection between the Big Rivers system and the KU system in Daviess County, Kentucky, and (2) a finding from the Public Service Commission ("Commission" or "PSC") that no certificate of public convenience and necessity ("CPCN") is required for the construction of the proposed interconnection. A copy of the Interconnection Agreement is attached hereto as Exhibit A. In support of this Application, Big Rivers states as follows:

I. Introduction

1. The applicant, Big Rivers, is a rural electric cooperative corporation organized pursuant to KRS Chapter 279. Its mailing address is P.O. Box 24, 201 Third Street, Henderson, Kentucky 42419. 807 KAR 5:001 Section 8(1).

2. Big Rivers owns generating assets, and purchases, transmits and sells electricity at wholesale. Its principal purpose is to provide the wholesale electricity requirements of its three distribution cooperative members: Kenergy Corp., Meade County Rural Electric Cooperative Corporation, and Jackson Purchase Energy Corporation.

3. A certified copy of the articles of incorporation of Big Rivers, and all amendments thereto, is attached as Exhibit 1 to the Application of Big Rivers in *In the Matter of: Application of Big Rivers Electric Corporation, LG&E Energy Marketing Inc., Western Kentucky Energy Corp., WKE Station Two Inc., and WKE Corp., Pursuant to the Public Service Commission Orders in Case Nos. 99-450 and 2000-095, for Approval of Amendments to Station Two Agreements*, PSC Case No. 2005-00532. 807 K.A.R. 5:001 Section 8(3).

4. This Application and the attached exhibits contain fully the facts on which the Application is based. 807 KAR 5:001 Section 8(1). The exhibits to this Application are the Interconnection Agreement (Exhibit A), a vicinity map showing the area where the proposed interconnection will be located (Exhibit B), a site map showing the facilities that will be constructed for the proposed interconnection (Exhibit C), an Interconnection Study (Exhibit D), and two graphs, one entitled Annual Export Needs vs Number of Hours Needed and the other entitled Big Rivers' Power Export Requirements, both showing the additional transmission export capability needed by Big Rivers (Exhibits E and F, respectively).

II. Description and History of the Interconnection Agreement

5. Big Rivers and KU have entered into the Interconnection Agreement subject to receipt of regulatory approvals, that cancels and supersedes a previous agreement between Big Rivers and KU dated September 1, 1989 (the "1989 Agreement"), and amended December 15, 1995 (the "1995 Amendment"), and that provides for an additional interconnection between the Big Rivers system and the KU system.

6. The transmission systems of Big Rivers and KU interconnect at several points. The parties entered into the 1989 Agreement to govern the operation of these interconnections, and to provide for capacity and energy supply transactions between the parties. The 1995

Amendment added a new interconnection point between the systems, established an additional service schedule for transmission losses, and modified the contract termination section to provide that the 1989 Agreement, as amended, would terminate no earlier than December 31, 2006.

7. On December 31, 2005, KU exercised its rights and sent a notice to Big Rivers of its intent to terminate the 1989 Agreement, as amended. The parties then negotiated and entered into the new Interconnection Agreement. The Interconnection Agreement eliminates the capacity and energy supply schedules from the 1989 Agreement and the transmission losses schedules from the 1995 Amendment. The Interconnection Agreement does not contemplate any transmission service or power supply between the parties. It only governs the overall operation and maintenance of the interconnection points between the two systems, and provides for an additional interconnection.

8. The cancellation of the 1989 Agreement will become effective upon the effective date of the Interconnection Agreement, which will occur on the date all regulatory approvals are received. KU is filing the Interconnection Agreement with the Federal Energy Regulatory Commission for its approval. Big Rivers requests Commission approval of the Interconnection Agreement. The authority of the Commission to grant this relief is found in 807 KAR 5:011 Section 13 and in the Commission's general jurisdiction under KRS 278.040 and KRS 279.210. 807 KAR 5:001 Section 8(1).

III. The Additional Interconnection

A. Description of the Proposed Interconnection

9. The Interconnection Agreement calls for two new interconnection points to interconnect an existing 345 kV transmission line owned by Big Rivers with an existing 345 kV transmission line owned by KU. The switching station for this interconnection will be located in

northeastern Daviess County, at a location immediately adjacent to the existing KU line and near the point where that line crosses the existing Big Rivers line. The map attached hereto as Exhibit B shows the vicinity where the switching station will be located. A site map showing both the Big Rivers and KU facilities that will be constructed or modified pursuant to the Interconnection Agreement is attached hereto as Exhibit C.

10. Since the switching station will be adjacent to the point of intersection of the existing 345 kV transmission line owned by KU and the existing 345 kV transmission line owned by Big Rivers, the line extensions required as part of the interconnection represent minor re-routes and terminations of each company's existing circuit.

11. The existing Big Rivers 345 kV line connects the D. B. Wilson Power Plant to the Coleman EHV Switchyard near the Coleman Power Plant. The only extension to the Big Rivers system involved in the interconnection project consists of the addition of two parallel 345 kV electric transmission lines (one that is 2467 feet in length and one that is 2481 feet in length), which will extend eastwardly from the switching station site to connect with that existing Big Rivers transmission line. The new lines will be located adjacent to each other on a single new transmission right-of-way ("ROW"), and will run nearly parallel to the existing KU ROW. The proposed lines will require a combined ROW width of 225 feet and will utilize steel structures. The average span between structures will be approximately 750 feet.

12. Similarly, only slight modifications will be necessary for the existing line owned by KU, which connects OMU's Elmer Smith Power Plant to KU's Hardin County Substation. One 606-foot span of the existing circuit will be separated into two spans and angled slightly to allow the circuits to be terminated in the proposed switching station. This will result in the existing circuit being looped in and out of the proposed switching station. These lines will each

require a ROW width of 150 feet and will utilize steel structures. Due to the very short length of these proposed lines, they will only involve one span length each, one of 268 feet and the other of 338 feet. Other than the modification to its transmission line, the only other change to KU's system is the addition of the switching station itself. Thus, the extensions and modifications to both the Big Rivers and KU systems are minimal.

B. The History of the Proposed Interconnection: the Need for Additional Export Capability

13. The purpose of the proposed interconnection is to meet a critical need for Big Rivers to increase its transmission export capability.

14. Big Rivers' need for additional export capability is identified in transmission studies Big Rivers completed as part of its normal system planning process and in a system impact study completed to evaluate a 450 MW transmission service request ("TSR") from Big Rivers Power Supply. These studies are discussed in the Big Rivers–Kentucky Utilities Interconnection Study ("Interconnection Study") attached hereto as Exhibit D. These studies contained an assessment of the ability of Big Rivers' transmission system to support the export of all excess Big Rivers control area generation under a range of contingencies. The contingencies considered include a loss of load from one or both of two large industrial customers located in the Big Rivers control area, both of which are aluminum smelters. As the Interconnection Study reveals, the loss of one or both of the smelter loads (either due to their contracts expiring in 2010 or 2011 or earlier due to some other cause), would result in significant excess generation (approximately 960 MW net export) in the Big Rivers control area for which Big Rivers does not have sufficient export capability available.

15. The need for additional export capability identified in the Interconnection Study is further illustrated in the graphs attached hereto as Exhibits E and F. The first graph (Annual

Export Needs vs Number of Hours Needed) shows the amount of export capability that Big Rivers needs, and the number of hours in a year for which the amount will be needed. For example, the Export '07 Need curve shows approximately 120 MW export capability will be needed for 8760 hours (the entire year) in 2007. It also shows that 200 MW export capability will be needed for approximately 8500 hours in 2007, and that 300 MW export capability will be needed for approximately 7500 hours in 2007. Similarly, the Export '11 Need curve shows that approximately 280 MW export capability will be needed for 8760 hours in 2011, and that 450 MW export capability will be needed for approximately 7800 hours in 2011.

16. The second graph (Big Rivers' Power Export Requirements) is a comparison of the load duration curve ("LDC") for Big Rivers' native load and the capacity available to Big Rivers. The LDC 2006 curve on this graph shows the number of hours that the load was above a select MW level in 2006. For example, the load was at least 225 MW for 8760 hours and the load was 628 MW for only one hour in 2006. The '06 LDC Shift '07 curve is the actual 2006 LDC shifted up relative to the forecast demand for 2007, and the '06 LDC Shift '11 curve is the 2006 LDC shifted up relative to the forecast demand for 2011. The Capacity 2007 curve is a straight line that indicates the total capacity available to Big Rivers in 2007, and the Capacity 2011 curve indicates the total capacity available to Big Rivers in 2011. The two extreme ends of the plot reveal that for one hour at maximum load, 118 MW of transmission is needed for export and for one hour at minimum load, 521 MW is needed for export in 2007; and that for one hour at maximum load, 282 MW of transmission is needed for export and for one hour at minimum load, 685 MW is needed for export in 2011. Subtracting the load at any point along the x-axis from the capacity at that same point yields the export capability needed by Big Rivers for a certain number of hours. For example:

a. for 7760 hours (at 1000 hours on the x-axis), the export capability that Big Rivers will need is at least 290 MW in 2007 and 454 MW in 2011; and

b. for 5260 hours (at 3500 hours on the x-axis), the export capability that Big Rivers will need is at least 374 MW in 2007 and 538 MW in 2011.

17. Currently, Big Rivers Power Supply effectively only has an export capability of 100 MW, and so, as the graphs show, Big Rivers would immediately benefit from additional export capability.

18. The export capacity shortfall is exacerbated in 2010 and 2011. On January 1, 2011, Big Rivers will receive another 120 MW of power under its Power Purchase Agreement with LG&E Energy Marketing, Inc. dated July 15, 1998, and on January 1, 2012, an additional 83 MW of power. Without additional export capability in place to handle this increase in its export requirements, Big Rivers risks having a substantial amount of excess capacity with no firm transmission path available to export that capacity out of the Big Rivers system.

19. Absent sufficient export capability, Big Rivers will suffer a lost financial opportunity because it will be unable to sell excess energy into the wholesale market in the quantity and at the quality that commands the highest sales prices. While a dollar amount of lost revenue is not possible to quantify, the number of MW that Big Rivers needs to have export capability for to be able to sell those MW's at the best available prices under the contingencies studies would include the 157 MW of smelter TIER 3 power and the 203 MW of additional power that will become available to Big Rivers in 2010 and 2011.

C. The Need for the Proposed Interconnection

20. The Interconnection Study identifies the proposed interconnection as the preferred option to address Big Rivers' need for additional export capability. It describes the transmission

planning studies and a system impact study that support the need for the proposed interconnection, the costs and benefits of the proposed interconnection, alternatives to the proposed interconnection that were considered, a short-circuit analysis for the proposed interconnection, a present worth analysis of the proposed interconnection, and Big Rivers' transmission planning criteria and guidelines.

21. Big Rivers has long recognized the proposed interconnection as the most logical option for increasing its transmission export capability, if and when additional capability is needed. Additionally, the proposed interconnection was included as one of the projects in the interconnection agreement between Big Rivers and Thoroughbred Generating Company, LLC ("Thoroughbred") that was approved by the Commission in its Order dated November 8, 2005 in *In the Matter of: Application of Big Rivers Electric Corporation for Approval of Electrical Interconnection Service to Thoroughbred Generating Company, LLC*, PSC Case No. 2005-00300, because studies in connection with that agreement revealed that the proposed interconnection project would be part of the most viable option available to meet Big Rivers' export capability requirements posed by the merchant generating facility proposed by Thoroughbred. The Interconnection Study confirms that the proposed interconnection is the preferred project to meet Big Rivers' export capability need, with or without the Thoroughbred project.

D. Alternatives Considered

22. The studies completed by Big Rivers evaluated several projects identified by Big Rivers personnel as alternative methods of adding the necessary export capability. These alternatives included the proposed interconnection, a 16 mile new-terrain 161 kV Wilson to Paradise (TVA) interconnection, and a 8.5 mile 345 kV double-circuit line from the Wilson to

Coleman EHV line to the OMU Elmer Smith substation. All three alternatives were found to be effective options, but the proposed interconnection project was selected because it was much less expensive than the other options, and because it could be constructed in the desired time frame. Other alternatives that were considered in addition to the three listed above were rejected because they did not provide the required export capability. The Interconnection Study describes these alternatives and the reasons behind the selection of the proposed interconnection project in more detail.

23. Once the proposed interconnection option was selected, Big Rivers also considered a total of five alternative sites at which to locate the proposed interconnection facilities. Two of these sites were eliminated early in the site selection process because the terrain at the two sites would have required extensive site preparation, and both sites have creeks or streams that would limit the useable size of the sites. Three other sites, including the proposed site, were more extensively evaluated for the proposed construction of the new switching station. One of these three sites is located approximately 3,000 feet east of the proposed site and east of the crossing of the two electric transmission lines. During the investigation of this site, Big Rivers determined that the two transmission lines, a natural gas pipeline, and a creek limited the useable size of the site and compromised its constructability. As a result, Big Rivers eliminated this site from further consideration. A second alternate site that was considered is located approximately 3,000 feet northeast of the proposed site near a natural gas pipeline which could have somewhat limited the useable size of the site. However, the landowner's refusal to sell the parcel of land in question was the primary reason that Big Rivers eliminated this site from consideration. The site ultimately selected by Big Rivers is not encumbered by other utilities, it is available for sale, and minimal site preparation for the switchyard is required.

E. Project Costs

24. Big Rivers will pay for all property and facilities necessary for the interconnection project (whether ultimately owned by Big Rivers or KU) with internally generated funds. Big Rivers will own the transmission lines on its side of the interconnection. KU will own the switching station (including the land Big Rivers will purchase) and the transmission facilities on its side of the interconnection. The total cost of the project, including the purchase price of the land, is estimated to be $6,600,000. Big Rivers' share of the estimated cost of operation of the new construction, including the cost of insurance, taxes, and operation and maintenance ("O&M"), based on historical averages, is 6.63% of the net book value of the transmission improvement per year and 4.30% of the net book value of the substation improvement per year, or approximately $130,000 per year.

F. Status of the Project

25. Construction of the proposed interconnection is scheduled for completion in August 2007. To meet this deadline, Big Rivers has recently put out construction bids with a construction time of 140-170 days from the date the contract is awarded. Additionally, Big Rivers has obtained options to purchase the property that will be required for the project, and to acquire the needed access road easements. All other transmission line easements required by Big Rivers have been acquired. One easement required by KU is under option for purchase. One final easement for the KU line modification has not yet been acquired; however, negotiations for this final easement are on-going and have been positive. Big Rivers is optimistic that an easement for this remaining parcel will soon be obtained. Big Rivers has obtained all approvals required from the Owensboro Metropolitan Planning Commission.

G. The Project is an Ordinary Extension of Big Rivers' System in the Usual Course of Business for which no CPCN is Required

26. Big Rivers is convinced that the project to establish another interconnection between the Big Rivers and KU transmission systems is a routine system improvement in the ordinary course of business, of modest cost, that does not require a CPCN. But since no objective guidelines exist for making this determination, and in the interest of assuring that Big Rivers is in compliance with all laws applicable to it, Big Rivers asks that the Commission make a finding that no CPCN is required under the circumstances presented. The only extensions to the Big Rivers system are the two parallel transmission lines, located on an easement which is less than 2500 feet in length. The proposed construction satisfies the requirements for an ordinary extension in the usual course of business under KRS 278.020(1)-(2) and 807 KAR 5:001 Section 9(3). The construction will not compete with any other public utilities, corporations, or persons; it will not create a wasteful duplication of plant, equipment, property or facilities; and it will not conflict with the existing certificates or service of any other utilities operating in or contiguous to Big Rivers' or KU's service area. The project does not involve sufficient capital outlay to materially affect the existing financial condition of Big Rivers, and will not it result in increased charges to Big Rivers' customers. Moreover, the interconnection does not involve the construction of a transmission line of more than a mile in length. Given the minimal cost of the project, the limited construction that will be required, and the fact that the construction was identified as a routine part of Big Rivers transmission planning, Big Rivers asks that the Commission find that the proposed interconnection constitutes an ordinary extension of an existing system in the usual course of business for which no CPCN is required. The authority of the Commission to grant this relief is found in KRS 278.020(1) and 807 KAR 5:001 Section 9(3). 807 KAR 5:001 Section 8(1).

WHEREFORE, Big Rivers requests that the Commission issue an order (1) approving the Interconnection Agreement, (2) finding that the proposed interconnection is an ordinary extension of an existing system in the usual course of business for which no CPCN is required, and (3) granting Big Rivers all other relief to which it may be entitled.

On this the 1st day of February, 2007.

SULLIVAN, MOUNTJOY, STAINBACK
& MILLER, P.S.C.

TKP

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Tyson Kamuf
100 St. Ann Building, P. O. Box 727
Owensboro, Kentucky 42302-0727
(270) 926-4000
Counsel for Big Rivers Electric Corporation

Verification

I, David G. Crockett, Vice President, System Operations for Big Rivers Electric Corporation, hereby state that I have read the foregoing Application and that the statements contained therein are true and correct to the best of my knowledge and belief, on this the 1st day of February, 2007.

David G. Crockett
Vice President, System Operations
Big Rivers Electric Corporation

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN to before me by David G. Crockett, as Vice President, System Operations for Big Rivers Electric Corporation, on this the 1st day of February, 2007.

Christa R. Gibson

Notary Public, State at Large KY
My commission expires: August 30, 2009

INTERCONNECTION AGREEMENT

BETWEEN

KENTUCKY UTILITIES COMPANY

AND

BIG RIVERS ELECTRIC CORPORATION

November 1, 2006

INTERCONNECTION AGREEMENT

THIS AGREEMENT, made and entered into this November 1, 2006, by and between KENTUCKY UTILITIES COMPANY (hereafter called KU), a Kentucky corporation, and BIG RIVERS ELECTRIC CORPORATION (hereafter called BR), a Kentucky corporation.

WITNESSETH:

WHEREAS, each of the parties is engaged in the business of generating, acquiring and selling electric capacity and energy and, for such purpose, owns and operates a control-—area electric power system including generation, transmission and related facilities; and

WHEREAS, the systems of the parties now are interconnected, and in the future may be further interconnected; and

WHEREAS, the parties desire to obtain for themselves the mutual benefits and advantages to be realized by coordinated operation of their systems in the manner and to the extent herein set forth; and

WHEREAS, the parties entered into an Interconnection Agreement dated September 1, 1989, as amended on December 15, 1995 (the ''1989 IA''); and

WHEREAS, the parties desire to enter into this Interconnection Agreement, which will cancel and supersede the 1989 IA;

NOW, THEREFORE, in consideration of the premises and the mutual agreements herein set forth, the parties agree as follows:

1. Points of Interconnection. The points of interconnection between KU and BR are specified in Appendix I, and shall be operated and maintained in accordance with the terms and conditions in this Agreement, including the Facility Schedule(s) listed in Appendix II attached to this Agreement, which are incorporated by reference herein.

2. Reserve Requirement. Each of the parties shall maintain and operate generation facilities and/or have contractual arrangements adequate to supply its own loads including adequate reserves; and the parties shall operate their respective facilities in synchronism.

3. Continuity of Interconnected Operation. If synchronous operation of the parties' systems becomes interrupted, the parties shall cooperate to remove the cause of the interruption as soon as practicable and restore their systems to normal interconnected operating condition.

4. Delivery. All electric energy delivered under this Agreement shall be of the character commonly known as three-—phase, sixty-hertz energy and shall be delivered at the nominal voltage(s) at the point(s) of interconnection.

5. Operating Committee. The interconnected operations of the parties' systems as provided for in this Agreement shall be administered by an Operating Committee, consistent with any directives of the Independent Transmission Organization (''ITO'') and/or Reliability Coordinator (''RC'') performing the functions as ITO/RC under the Open Access Transmission Tariff of either KU or BR as then effective. Each party shall appoint one member and an alternate to the Operating Committee. The principal duties of the Operating Committee shall be as follows;

a) To establish operating, scheduling and control procedures

b) To establish accounting and billing procedures;

c) To coordinate maintenance schedules, to any extent agreed by the parties;

d) To perform those duties which this Agreement requires to be done by the Operating Committee and such other duties as may be required for the proper functioning of this Agreement.

If the Operating Committee is unable to agree on any matter coming under its jurisdiction, that matter shall be referred to the chief executives of the parties, or their designated representatives.

6. [RESERVED]

7. [RESERVED]

8. System Control. Each party shall establish energy schedules with the dispatcher of the other before intentionally taking any energy from the system of the other. Neither party shall impose any burden upon the facilities of the other in excess of their safe and proper capacity as determined by the Operating Committee pursuant to the provisions of Section 5 of this Agreement or in excess of that contractually agreed to by the owner of the facilities. If emergency conditions arise which overload the interconnecting facilities between the systems of the parties, both parties shall cooperate in taking immediate steps to eliminate such overload condition, but the party on whose system the action or condition giving rise to the overload occurs shall have the primary responsibility for such corrective action.

9. Reactive Power and Voltage Regulation. Insofar as practicable, each party shall operate its system so as to

generate or otherwise obtain substantially all of the reactive power required by its own system and to maintain satisfactory voltage levels. The parties' dispatchers shall have sufficient latitude, when dispatching reactive power, to obtain the most satisfactory interconnected system operation without working any undue hardship on either party by reason of the generation or absorption of a disproportionate amount of reactive power.

10. Energy Losses. The energy losses on the interconnecting facilities shall be assigned to the party in whose control area the facilities are located according to procedures developed by the Operating Committee.

11. Metering and Communications. Metering facilities for determination of the quantities of capacity and energy under this Agreement shall be located as near as practicable to the point or points of interconnection of the systems and, if appropriate, shall include line loss compensation equipment such that the effective points of metering are at the points of interconnection. The parties by agreement will establish responsibility for installation, ownership and operation of all metering equipment necessary to provide KW and KWH quantities of interconnection power flows for the systems' power control and accounting purposes. The agreement between the parties with respect to metering equipment locations for the respective points

of interconnection is specified in Appendix I and Appendix II.

The metering equipment required herein shall be installed, operated and maintained by the owner in accordance with good engineering practice. Meters owned by the parties at points of interconnection with each other shall be routinely tested and inspected annually, and within 60 days after installation or a change of instrument transformers. The party owning the meter shall give reasonable advance notice of all tests and inspections, so that representatives of the other party may be present. The owner of a meter shall bear the expense of such routine meter tests and inspections. Additional tests and inspections of meters shall be made whenever requested by the other party; provided, however, that if a party requests such an additional test of a meter or meters of the other party and such test(s) show the meter(s) to be accurate within 1% fast or slow, the requesting party shall pay the cost of such test(s). If any test or inspection of a meter shows it to be inaccurate by more than 1% fast or slow, an adjustment in deliveries shall be made during the following month to adjust for the amount by which the meter was shown to have been in error for the preceding period of inaccuracy. If the period of inaccuracy is not known, it shall be assumed to be one-—half the interval since the last preceding test. The meter or other equipment found to be inaccurate or defective shall be promptly repaired, adjusted or replaced by the owner of that meter. The party owning the interconnection terminal facilities at or nearest the point of interconnection shall provide space, and power supply for telemetering equipment of the other party, either at no charge or at an agreed charge. Each party shall provide its own communication path for telemetering signals. Additional equipment may be installed or metering facilities may be modified or improved as agreed to by the Operating Committee.

12. <u>Bills and Payments.</u> Net billing of transactions subject to this Agreement will be used between the parties. Bills will be rendered by the party owed the net amount and will show all costs and deliveries in each direction, including the amount owed and the net amount to be paid according to the terms of this Agreement. All bills for net amounts owed by either party to the other shall be due and payable on the fifteenth day (or the first business day after the fifteenth if the fifteenth is not a business day) of the month next following the monthly or other period to which such bills are applicable, or on the tenth day (or the first business day after the tenth if the tenth is not a business day) following receipt of bill, whichever date is later. Unless otherwise agreed upon, a calendar month shall be the standard monthly period for purposes of settlements hereunder. Interest on amounts not paid when due shall accrue daily from the due date at the rate specified by the Federal Energy Regulatory

Commission for refunds to wholesale customers as contained in FERC Regulation No. 35.19a, or its appropriate revision.

13. Taxes. Should any federal, state or local tax, in addition to such taxes as my now exist, be levied upon any capacity or energy to be sold hereunder, or upon the sale thereof, or upon the seller measured by the capacity or energy or the revenue there from, or upon any transaction hereunder or the revenue there from, such tax shall be added to the net bill as determined under the appropriate rates and billing procedures.

14. Uncontrollable Circumstances. Neither party shall be considered to be in default of any obligation hereunder, if prevented from fulfilling such obligation by reason of an Uncontrollable Circumstance. As used herein, the term ''Uncontrollable Circumstance'' means any circumstance or cause beyond the control of the party affected, including but not limited to such causes as failure of facilities or of fuel or other material supplies, flood, earthquake, storm, lightning, fire, epidemic, war, riot, civil disturbance, labor disturbance, sabotage, collision or restraint or order of court or public authority having jurisdiction, whether or not caused or contributed to, or alleged to have been caused or contributed to, by negligence of the party affected, or intentionally caused if in a good faith effort by the causing party to preserve the operating integrity of

its own system or of the systems of the parties. Any party unable to fulfill any obligation by reason of an Uncontrollable Circumstance shall give notice to the other party and shall remove said disability with reasonable dispatch, except that any labor disturbance or other difference with an entity or entities not party hereto may be settled at the discretion of the party hereto directly affected thereby. In the event of continuing delays, only one notice is necessary.

15. Non-—liability for Interruption or Failure of Performance. In the event that, as applied to any occurrence or situation, there shall be a conflict between any provision in this Section 15 and any other provision(s) in this Agreement or any Facility Schedule or other addendum hereto or amendment hereof, the provision in this Section 15 shall be controlling. Each party hereto intends to diligently, in good faith and fully performs its obligations hereunder. However, it is not the intention of the parties to, and neither party does, guarantee the ability to perform, or the continued performance of, obligations undertaken hereunder to supply capacity or energy or service of any character, including Firm Power and Short-Term Firm Power, or other obligation of any kind. Accordingly, it is expressly agreed that neither party shall have any liability of any kind or nature to the other party, or to any other entity of any kind including any customer of any party or other entity, arising out of any failure or interruption

of delivery or supply of capacity or energy or service, hereunder or under any addendum hereto or amendment hereof, even though such interruption or failure was caused or contributed to, or is alleged to have been caused or contributed to, by negligence of the supplying or charged party, or was intentionally caused if in a good faith effort by the causing party to preserve the operating integrity of its own system or of the systems of the parties. Each party accepts, without claim against or liability on the part of the other, the risks of and losses from such interruptions or failures in the other's performance, the same as if they had been caused by acts or omissions of its own employees or failures of its own equipment or events occurring on its own system.

16. Operation and Maintenance. Unless otherwise provided by this Agreement, each Party shall, at its own risk and expense (a) use commercially reasonable efforts to operate and maintain all points of interconnection specified in Appendix II of this Agreement, and (b) design and install equipment and facilities (including all apparatus and necessary protective devices) on its side of each Point of Interconnection when added in accordance with this Agreement and applicable Facility Schedules, in each case, in accordance with Good Utility Practice so as to reasonably minimize the likelihood of a disturbance originating on its Transmission System or Interconnection Facilities from affecting or impairing the other Party's

Transmission System or Interconnection Facilities or other transmission systems to which it is interconnected.

17. Parties in Interest. The parties hereto shall be the only parties in interest to or in any manner benefited by this Agreement. This Agreement is not intended to and shall not create rights of any character whatsoever in favor of any person, corporation, association, entity or power supplier or customer, other than the parties, and the obligations herein assumed by the parties are solely for the use and benefit of the parties. Nothing herein contained shall be construed as permitting or vesting, or attempting to permit or vest, in any person, corporation, association, entity or power supplier or customer, other than the parties, any right hereunder or in any of the electric facilities owned by the parties or the use thereof.

18. Government Regulation. This Agreement shall become effective only when accepted for filing, without change, by the Federal Energy Regulatory Commission and all other governmental agencies having jurisdiction hereof. Nothing contained herein shall be construed as affecting in any way the right of either party hereto, and each party hereto shall at all times have the right, to unilaterally file with the Federal Energy Regulatory Commission, or other regulatory agency having jurisdiction, a change in rates, charges, classification, or any rule, regulation or contract

relating thereto, under Section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated there under, or under other applicable statutes and regulations. In the event of any change by any regulatory agency, or by either party acting unilaterally, in any term or provision herein, or in any rate, charge, classification or service hereunder, or any rule, regulation or contract relating thereto, any party not having sought such change or concurred therein in writing, may terminate this Agreement immediately by written notice to the other party.

19. Extent of Permission Granted. Each party is herein granted permission and right to make use of facilities of the other only to any extent herein expressly stated or necessary to the consummation of transactions between the parties entered into hereunder, and no party is herein granted any permission or right to make any other use of any facility of the other without such other party's written consent.

20. Notices. Any written notice required or appropriate hereunder shall be deemed properly made, given to, or served on the party to which it is directed, when sent by United States mail addressed as follows:

if to KU, to Director, Transmission
E.ON U.S. Services, Inc.

P.O. Box 32020
Louisville, Kentucky 40232

If to BR, to President & CEO
Big Rivers Electric Corporation
P.O. Box 24
Henderson, Kentucky 42419

Notice of any change in either of the above addresses shall be given in the manner specified in this Section 19.

21. Term and Termination of Agreement. This Agreement may be terminated immediately by either party, by written notice to the other, upon such other's violation of any term or provision hereof, and upon failure to remedy such deficiency within 30 days or such longer period as applicable law may require, after receipt of a notice, which specifies the deficiencies and lists the steps that must be taken to correct such deficiency according to the terms of this Agreement. Subject to such provision and to the provisions of Section 18, this Agreement shall be effective as of August 1, 2006, or such later date as the last necessary regulatory approval hereof shall be obtained, and shall remain in effect for a term of one year and thereafter, until terminated by either party effective August 1, 2007, or any date thereafter, upon not less than one year's prior written notice of such termination to the other party.

22. Successors and Assigns. This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the

parties, but shall not be assigned by either party without the prior written consent of the other, except to a successor to all or substantially all of the properties and business of such assigning party.

23. Indemnification. KU shall indemnify and hold harmless BR from any and all claims, demands, or causes of action for loss of life or for loss, injury, or damage to persons or property arising out of or in any way connected with the performance by KU of this Agreement, except to the extent such loss of life or loss, injury, or damage to persons or property is caused by the negligence or willful misconduct of BR, its agents, servants, or employees.

BR shall indemnify and hold harmless KU from any and all claims, demands, or causes of action for loss of life or for loss, injury, or damage to persons or property arising out of or in any way connected with the performance by BR of this Agreement, except to the extent such loss of life or loss, injury, or damage to persons or property is caused by the negligence or willful misconduct of KU, its agents, servants, or employees.

24. Bankruptcy. In the event either party makes an assignment for the benefit of creditors or an admission of that party's inability to pay its obligations as they become due, or

files a voluntary petition in bankruptcy or any pleading seeking any reorganization, arrangement, composition, adjustment, liquidation, dissolution or similar relief under any law, or admitting or failing to contest the material allegations of any such pleading filed against the party, or is adjudicated a bankrupt or insolvent, or a receiver is appointed for a substantial part of the assets of the party, or the claims of creditors of the party are abated or subject to a moratorium under any law, this Agreement shall terminate immediately; provided however, the other party may, at its discretion, reinstate this Agreement until the parties agree otherwise. Within 60 days of the filing of any bankruptcy proceedings by or against either party, such party agrees that it will assume or reject this Agreement under Section 365 of the U.S. Bankruptcy Code pertaining to executory contracts without the filing of a motion by the other party.

25. Cancellation of Prior Agreements. When effective, this Agreement shall cancel and supersede the Interconnection Agreement between KU and BR dated September 1, 1989.

IN WITNESS WHEREOF, the parties have caused this Agreement to be executed and attested by their duly authorized officers, as of the day and year written first above.

KENTUCKY UTILITIES COMPANY

By: Lonnie Bellar

Name: Lonnie Bellar

Title: Director, Transmission

BIG RIVERS ELECTRIC CORPORATION

By: Michael Core

Name: Michael Core

Title: President & CEO

Appendix I

1 The following are existing Interconnection Points as of the date of this Agreement:

1.1 The point hereby designated as ''Hardinsburg Interconnection Point''. This point is where BR's 138 kV single circuit transmission line extending from BR's Hardinsburg 138 kV Station is connected at KU's Hardinsburg 138kV Station. The interconnection metering is owned by KU and is located in KU's Hardinsburg 138kV Station.

1.2 The point hereby designated as ''Green River Interconnection Point''. This point is where BR's 161 kV single circuit transmission line extending from BR's Wilson 345/161 kV Station is connected to the KU Green River 161/138/69 kV Station. The interconnection metering is owned by KU and is located in the KU Green River 161/138/69 kV Station.

2 The following are new Interconnection Points which have been agreed to by KU and BR upon execution of this Agreement:

2.1 The point hereby designated as ''Daviess County #1 Interconnection Point''. This point is where BR's 345 kV single circuit transmission line extending from BR's Wilson EHV Station is connected to the new KU Daviess County 345 kV

Station to be constructed. The facilities to be constructed and the cost responsibilities by each party for the establishment of this Interconnection Point are described in Appendix II, Facility Schedule 1.

2.2 The point hereby designated as ''Daviess County #2 Interconnection Point''. This point is where BR's 345 kV single circuit transmission line extending from BR's Coleman EHV Station is connected to the new KU Daviess County 345 kV Station to be constructed. The facilities to be constructed and the cost responsibilities by each party for the establishment of this Interconnection Point are described in Appendix II, Facility Schedule 1.

Appendix II

Facility Schedule 1

Terms for development of the Daviess County #1 and Daviess County #2 Interconnection Points:

1 Construction of facilities required to establish the Daviess County #1 and Daviess County #2 Interconnection Points. The Daviess County #1 and Daviess County #2 Interconnection Points shall be constructed and maintained per the following terms:

1.1 BR, at its expense, shall construct, or cause to be constructed and KU will own, operate, and maintain the Daviess County Substation and related terminal equipment as pictured in Attachment F1-A, attached to this Facility Schedule.

1.2 BR, at its expense, shall modify, or cause to be modified, terminal relay equipment at the Wilson EHV Substation and the Coleman EHV Substation to facilitate the addition of the Daviess County Substation and will coordinate with the operation of KU's facilities.

1.3 KU, at BR's expense, shall modify, or cause to be modified, terminal relay equipment at the Owensboro Municipal Utilities Smith Plant Substation and the KU Hardin County Substation to facilitate the addition of the Daviess

County Substation.

1.4 BR, at its expense, shall provide, or cause to be provided, own, operate, and maintain at KU's Daviess County Substation site any communications, telemetering and data acquisition facilities required by BR in connection with this Agreement. KU will provide or cause to be provided, at BR's expense, and own, operate, and maintain the necessary telemetry and metering data interface necessary for interconnection metering and protection required by KU at its Daviess County Substation. BR's equipment at the Daviess County Substation site will be located such that BR can perform the necessary maintenance on this equipment without the accompaniment or presence of KU personnel.

2 Approval of Specification and Design. BR shall submit the specifications and design for the KU Daviess County Substation and related terminal equipment to KU for review prior to construction of such facilities in order to ensure that connection of the facilities to the KU System is consistent with operational control, reliability and/or safety standards or requirements of the KU System. BR shall reimburse KU in accordance with Section 12 of this Agreement for all properly documented, reasonable and necessary costs and expenses that KU incurs in evaluating the design of facilities subject to this Agreement. KU's review of the specifications and design

shall be construed neither as confirming nor as endorsing the design, nor as any warranty as to fitness, safety, durability or reliability of facilities to be constructed. Notwithstanding, KU shall have sole discretion to determine the appropriate equipment and related facilities for the KU Daviess County Substation and related terminal equipment. To the extent that BR objects to KU's determination of appropriate equipment and related facilities, and KU and BR are unable to mutually agree on alternative specifications, design, equipment and/or settings for the facilities to be constructed, KU shall have the option to either: (i) notify BR in writing of KU's decision to require specific changes to the specifications, design, equipment and/or settings of the facilities; or (ii) notify BR in writing that KU objects to specified items of the specifications, design, equipment and/or settings of the facilities, and the specific changes KU would require in order to accept such specifications, design, equipment and/or settings, but that KU will nevertheless allow use of the specifications, design, equipment and/or settings. If KU chooses option (i), KU shall be responsible for all damages, but excluding consequential damages such as lost profits and liquidated damages, including any personal injuries, death, or other damages, penalties, charges and fines, resulting from the changes required by KU, and KU shall defend, indemnify, and hold harmless BR against any and all claims, demands, or actions and all judgments, decrees, and awards rendered with respect thereto. *If KU chooses option* (ii), BR shall have the option to either: (a) notify KU in writing of BR's concurrence with the changes specified by KU in its notification, in which event KU shall have the same responsibilities and provide the same indemnification as if KU had selected option (i); or (b) notify KU in writing of its decision to use the specifications, design, equipment and/or settings to which KU objected in its notification, in which event BR shall be responsible for all damages, but excluding consequential damages such as lost profits and liquidated damages, including any personal injuries, death, or other damages, penalties, charges and fines, resulting from such specifications, design equipment and/or settings, and BR shall defend, indemnify, and hold harmless KU, its parents, subsidiaries, affiliates, and their partners, members, officers, directors, employees, agents, contractors, representatives, and assigns from and against, any and all claims, demands, or actions and all judgments, decrees, and awards rendered with respect thereto.

3 Related Upgrades. The study attached as Attachment F1-B hereto indicates that the Elizabethtown 138 kV bus will overload with maximum generation in the BR control area. KU agrees, at BR's

expense, to upgrade the Elizabethtown 138 kV bus. BR shall reimburse KU its properly documented, reasonable, and necessary costs for this work. This cost is estimated to be about $20,000. Reimbursement shall be per the terms of Section 12 of this Agreement.

4 Flowgate recognition. The attached study indicates that under certain conditions with the new interconnections the KU Hardin County to Elizabethtown 138 kV transmission line and/or the KU Ohio County to Shrewsbury 138 kV transmission line can be caused to overload, together referenced herein as KU Flowgates. BR agrees to recognize the posted ''Available Flowgate Capability'' for KU flowgates, as defined in the Joint Reliability Coordination Agreement among and between MISO, PJM and TVA in evaluating and approving Firm Point-to-Point Transmission Service requests under the BR Open Access Transmission Tariff. KU agrees to recognize the posted ''Available Flowgate Capability'' for BR flowgates, as defined in the Joint Reliability Coordination Agreement among and between MISO, PJM and TVA, for the KU Flowgates above in evaluating and approving Firm Point-to-Point Transmission Service requests under the LG&E/KU Open Access Transmission Tariff.

5 Future Maintenance Costs of the KU Daviess County Substation.

BR agrees to reimburse KU for the properly documented, reasonable, and necessary costs of maintaining, repairing, or replacing the breakers and associated bus work for the Daviess County #1 or Daviess County #2 Interconnection Points and the costs of maintaining the 345 kV bus of the Daviess County Substation. If KU should, in the future, expand or modify the Daviess County Substation for its own use and benefit or for the benefit of any third party, then BR and KU shall re-define the responsibilities of each party with respect to maintenance, repair, and replacement costs thereafter. Reimbursement shall be per the terms of Section 12 of this Agreement.

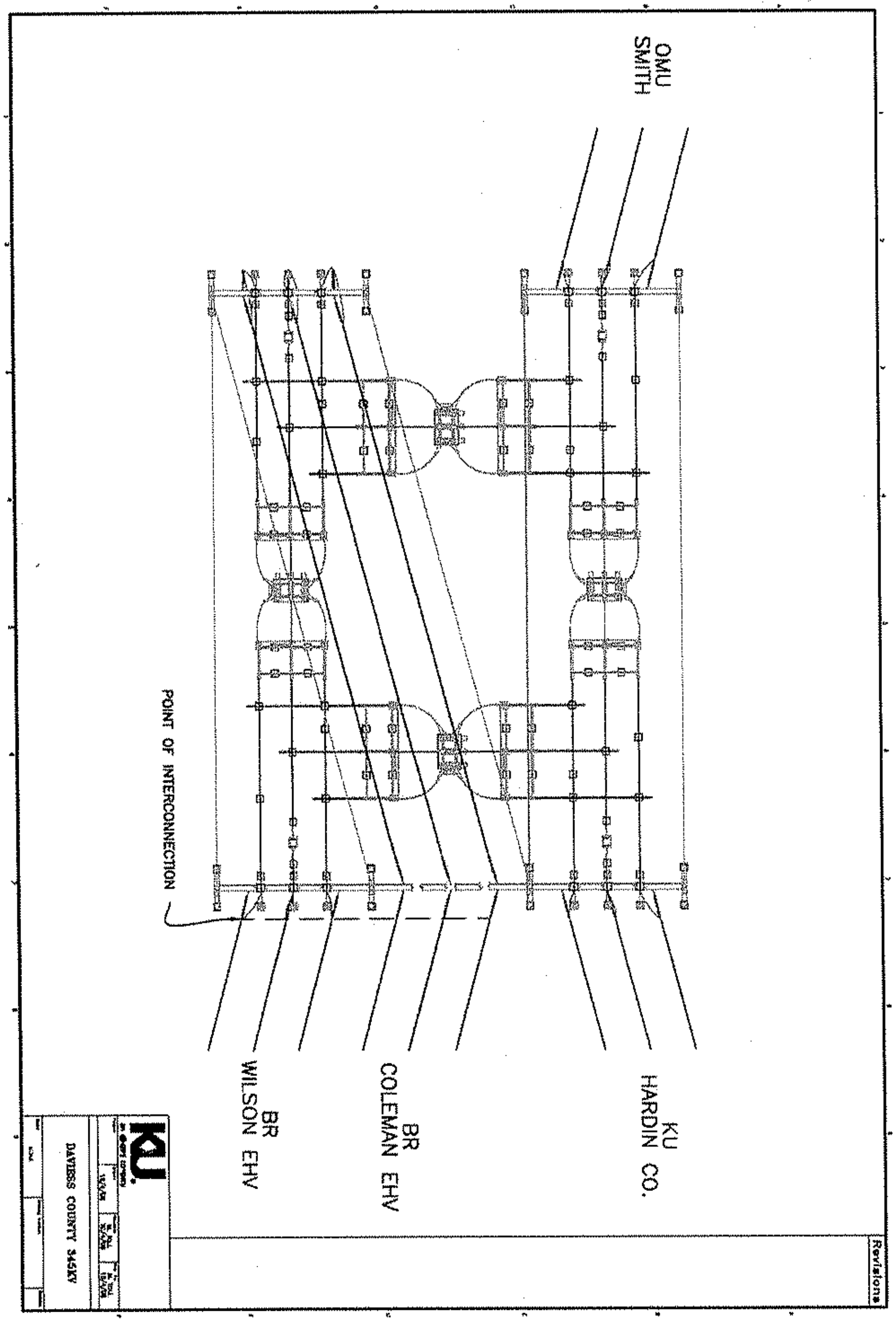
6 Completion Date. Unless otherwise agreed, the review, construction, and installation of facilities provided for under Sections 2 and 3 of this Appendix shall be scheduled for completion and the facilities scheduled to be ready for operation by June 1, 2007, unless Uncontrollable Circumstances affect such completion. In any event, the facilities shall not be energized until all necessary approvals have been received.

7 Reimbursement to KU. All costs relating to the construction of the facilities described in Sections 2 and 3 of this Appendix (''the Project'') shall be borne solely by BR. BR shall reimburse KU for all properly documented, reasonable, and necessary costs expended by KU to complete the Project.

8 Approvals. In addition to government approvals referred to in Section 17 of this Interconnection Agreement of which this Appendix II Facility Schedule 1 is made a part, this Facility Schedule is subject to approval of all governmental and financing authorities having jurisdiction, and whose approval or consent is required, including without limitation, utility and environmental regulatory authorities, and the Rural Utilities Service of the United States. Each party shall notify the other in writing when it has received all approvals required for its portion of the construction described in Sections 2 and 3 of this Appendix. If any required approval is denied, the affected party shall give written notice of such denial to the other party, neither party shall have any liability to the other under this Facility Schedule, and this Facility Schedule shall have no further effect.

Appendix II

Attachment F1-A



Appendix II

Attachment F1-B

Study Results

The following cases were evaluated with the addition of the Daviess County Substation for the 2007 Summer, 2010 Summer w/o TC2 and 2010 Summer:

0	Existing system, Base BREC generation
1	345 kV interconnection, Base BREC generation
1a	345 kV interconnection, BREC max gen
2	345 kV interconnection, Coleman area smelter gone, BREC max gen
3	345 kV interconnection, Reid area smelter gone, BREC max gen

The 07s1a case indicates that the 345 kV interconnection and max BREC generation will cause an overload of Hardin Co to Elizabethtown 138 kV until EKPCs line into Wilson is complete. The agreement needs to include replacement of the 138 kV bus at Elizabethtown at the time of the 345 kV interconnection. Rough cost $20,000.

If either smelter leaves before EKPCs line is compete and the extra power is attempted to be exported, then the Ohio Co to Shrewsbury 138 kV line (28 miles) will need to be upgraded to 212F operation (Cases 07s2 and 07s3). The 2010 results show that this will no longer be a problem after the completion of the EKPC line into Wilson.

Issues Contingency List

2007 Summer (w/o BREC-EKPC 161 kV line from Wilson)

Dispatch	Contingency	Facility	Rate	07s0	07s1	07s1a	07s2	07s3	
br3_tc_cin	HARDN CO 345-BROWN N 345 1	HARDN CO 138.00-ETOWN 138.00 1	246			280.3	285.3	265.1	Replace 500 MCM bus
br3_tc_cin	HARDN CO 345-KU_to_BR 345 1	SHREWSBU 138.00-OHIO CO 138.00 1	168				190.5	186.7	Upgrade 28 mi of conductor to 212F
ws1_cm_cin	14WILSO7 345-14REID 7 345 1	14REID 5 161.00-14DAVIS5 161.00 1	265	269.3		276.8		387.9	BREC Limit

2010 Summer (w/o Trimble Co 2)

Dispatch	Contingency	Facility	Rate	10s11	10s11a	10s12	10s13	
cm3_ws_tva	14WILSO7 345-14REID 7 345 1	14REID 5 161.00-14DAVIS5 161.00 1	265				381.2	BREC Limit

2010 Summer

Dispatch	Contingency	Facility	Rate	10s20	10s21	10s21a	10s22	10s23	
br3_tc_cin	ROGERSVL 138-HARDN CO 138 1	HARDN CO 138.00-ETOWN 138.00 1	247	273	277.6	283.9	300.9	291.6	Other issues will reduce flow
cm3_ws_tva	14WILSO7 345-14REID 7 345 1	14REID 5 161.00-14DAVIS5 161.00 1	265					377.6	BREC Limit

Non-Issues Contingency List

2007 Summer (w/o BREC-EKPC 161 kV line from Wilson)

Dispatch	Contingency	Facility	Rate	07s0	07s1	07s1a	07s2	07s3
br3_tc_cin	TRIMBLCO 345-06CLIFTY 345 1	BLUELICK 345.00-BLUELICK 161.00 1	275	274				
mbr_mc4	BROWN N 138-HIGBY ML 138 1	BROWN N 138.00-BAKER EK 138.00 1	274	273	275	278	284	283
mbr_mc4	BROWN N 138-BAKER EK 138 1	BROWN N 138.00-HIGBY ML 138.00 1	246	269	270	274	279	278
mbr_mc4	W LEXNGT 345-W LEXNGT 138 1	BROWN N 138.00-PISGAH 138.00 1	190	193	195	198	204	202
mbr_mc4	W FRNKFT 345-GHENT 345 1	BROWN N 138.00-TYRONE 138.00 1	176				178	177

br3_tc_cin	HARDN CO 345-KU_to_BR 345 1	GR RV ST 138.00-SMITH 138.00 1	260			267		Unverified 165F Conductor Limit - nonissue
br3_tc_cin	HARDN CO 345-KU_to_BR 345 1	HARDINSB 138.00-HARDN CO 138.00 1	246			244		500 MCM bus - Insignificant <30k
gr4_tc_cin	14WILSO7 345-BR_to_KU 345 1	14WILSO5 161.00-GR RVR 161.00 1	558				558	

2010 Summer (w/o Trimble Co 2)

Dispatch	Contingency	Facility	Rate	10s11	10s11a	10s12	10s13
mbr_mc4	BROWN N 138-HIGBY ML 138 1	BROWN N 138.00-BAKER EK 138.00 1	274	283	286	292	290
mbr_mc4	BROWN N 138-BAKER EK 138 1	BROWN N 138.00-HIGBY ML 138.00 1	274	279	282	287	286
mbr_mc4	W LEXNGT 345-W LEXNGT 138 1	BROWN N 138.00-PISGAH 138.00 1	192	194	197		201
mbr_mc4	BROWN N 138-HIGBY ML 138 1	HIGBY ML 138.00-BAKER EK 138.00 1	246			245	244
mc4_br_cin	PADDYRUN 138-PR 3 MP 999 1	PADDYRUN 138.00-DIXIE 138.00 1	191	193	193	194	193
mbr_mc4	W CLIFF 138-BROWN P 138 2	W CLIFF 138.00-BROWN P 138.00 1	300	299	300	303	301

2010 Summer

Dispatch	Contingency	Facility	Rate	10s20	10s21	10s21a	10s22	10s23
mbr_mc4	BROWN N 138-HIGBY ML 138 1	BROWN N 138.00-BAKER EK 138.00 1	274	273	273	275	279	278

mbr_mc4	BROWN N 138-BAKER EK 138 1	BROWN N 138.00-HIGBY ML 138.00 1	274				274	273	
mbr_mc4	W LEXNGT 345-W LEXNGT 138 1	BROWN N 138.00-PISGAH 138.00 1	192	196	196	198	201	200	
br3_tc_cin	HARDN CO 345-BROWN N 345 1	NELSONCO 138.00-ETOWN 138.00 1	155				158		Unverified 145F conductor Limit - nonissue
Base	PADDYRUN 138-PR 3 MP 999 1	PADDYRUN 138.00-DIXIE 138.00 1	191	193	193	193	193	193	
mbr_mc4	W CLIFF 138-BROWN P 138 2	W CLIFF 138.00-BROWN P 138.00 1	300		301	301	303	302	

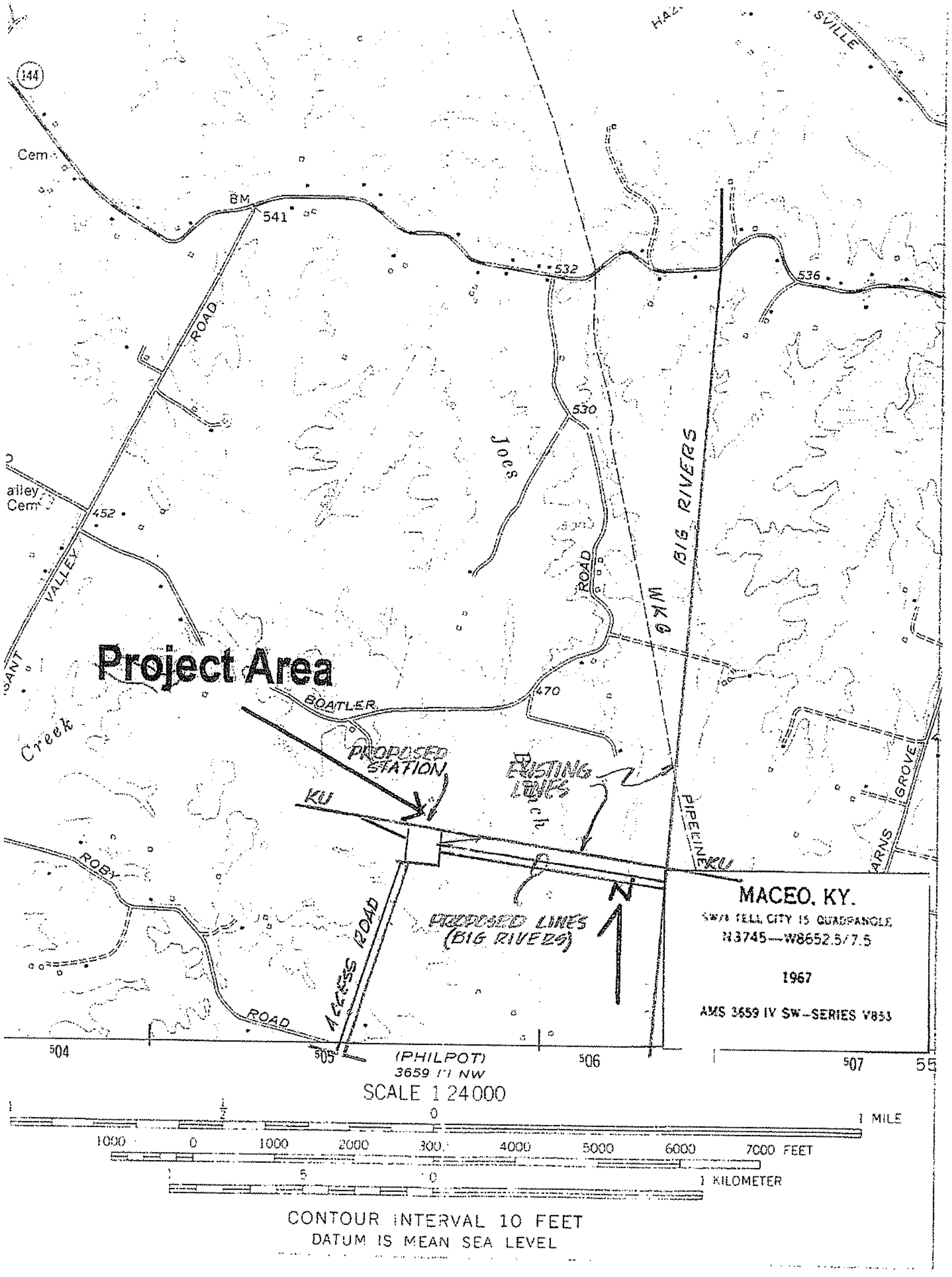


Exhibit B 1967 Maceo, KY USGS 7.5-minute topographic quadrangle showing the location of the project area.

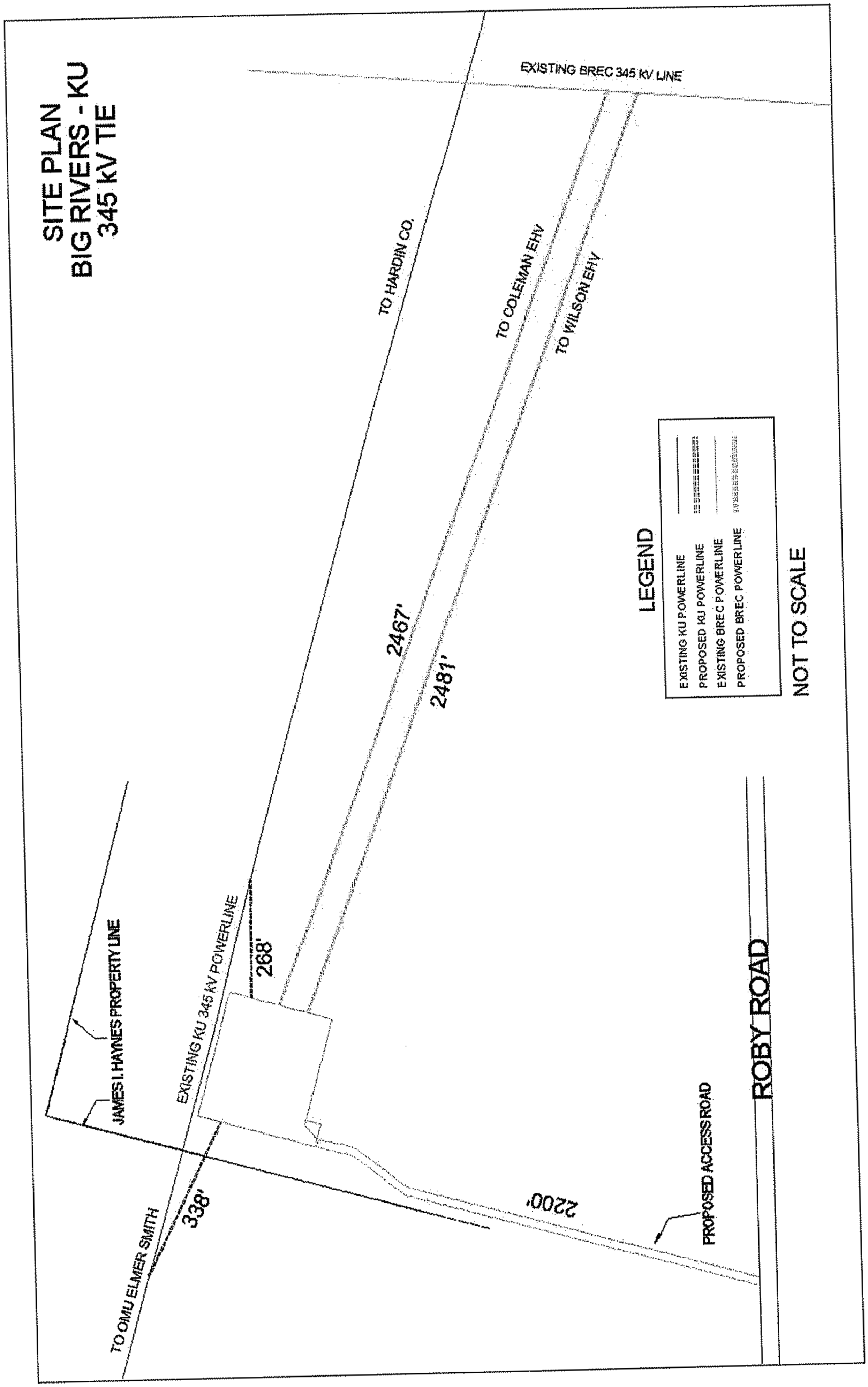

SITE PLAN
BIG RIVERS - KU
345 kV TIE
EXISTING BREC 345 kV LINE
TO HARDIN CO.
TO COLEMAN EHV
TO WILSON EHV
2467'
2481'
LEGEND
EXISTING KU POWERLINE
PROPOSED KU POWERLINE
EXISTING BREC POWERLINE
PROPOSED BREC POWERLINE
NOT TO SCALE
JAMES I. HAYNES PROPERTY LINE
EXISTING KU 345 kV POWERLINE
268'
338'
TO OMU ELMER SMITH
2200'
PROPOSED ACCESS ROAD
ROBY ROAD

Exhibit C

Big Rivers
Electric Corporation

Big Rivers - Kentucky Utilities Interconnection Study

December 2006

Exhibit D

TABLE OF CONTENTS

Page

I. INTRODUCTION

Two large industrial loads served within the Big Rivers Electric Corporation (Big Rivers) control area have contracts that will expire in 2010 and 2011. The loss of one or both of these loads, either at the time of contract expiration or before, would result in significant excess generation in the Big Rivers control area. In the absence of a large load addition, the ability to export this generation outside the Big Rivers control area is critical. Therefore, Big Rivers has completed transmission studies to assess the ability to export excess generation during various system conditions. In particular, the studies focused on assessing the ability of the transmission system to support the export of all excess Big Rivers control area generation with the loss of the Century Aluminum load, the ALCAN load, or the loss of both of these aluminum smelters.

In addition, studies have been completed to evaluate a 450 MW Big Rivers Power Supply (BRPS) transmission service request (TSR). If approved, this yearly-firm TSR will provide a 450 MW path for generation sourced from the Big Rivers control area to a sink in the MISO system. With the existing system (generation and load levels), Big Rivers control area generation is insufficient to source transactions that would fully utilize the TSR. Therefore, the TSR system impact study included a loss of smelter load.

After these studies were completed, a management review resulted in the selection of a 345 kV Big Rivers to Kentucky Utilities Company (KU) interconnection as the preferred near-term alternative to provide improved export capability. This document describes the completed studies, the expected costs, and the benefits of the proposed interconnection. The criteria and procedures employed by Big Rivers during the completion of the described studies and analyses are included in Appendix E.

II. GENERAL DISCUSSION

Throughout 2004 and continuing in 2006, various studies were completed in order to evaluate various export scenarios. These studies included loss of load scenarios. The most critical load loss studies included the loss of one or both of the aluminum smelters (Century Aluminum and ALCAN) located in the Big Rivers control area. Since the existing transmission system is unable to support additional power exports (all annual firm transmission has already been sold), multiple interconnections and system enhancements alternatives were evaluated.

The existing Big Rivers bulk transmission system is primarily a 161 kV system with 138 kV facilities at two interconnection points and two 345 kV circuits that interconnect the generating stations. This system has no EHV interconnections and was not designed to transfer large amounts of power to load outside the Big Rivers control area. Consequently, transmission enhancements that provide additional paths to either existing load centers or the EHV transmission system were found to be necessary to accommodate large power exports.

A previously prepared generator interconnection study identified the need for additional outlets (interconnections with neighboring utilities) during system conditions that include increased power exports from Big Rivers. More specifically, two interconnections were required to support the addition of 750 MW of generation to the Big Rivers transmission system. Since both interconnections were found to increase the ability to export power, both were evaluated as part of the aluminum smelter load loss studies.

The interconnections evaluated as part of the generator interconnection study and again evaluated as part of the load loss studies included a 16 mile new-terrain 161 kV Wilson to Paradise (TVA) interconnection. Also included was the proposed 345 kV substation addition that will connect the Big Rivers owned Wilson to Coleman EHV circuit to KU. The proposed substation will be constructed near the point this existing Big Rivers 345 kV circuit intersects the Elmer Smith to Hardin County 345 kV circuit. An alternative to this substation addition includes an 8.5 mile 345 kV double-circuit line from the Wilson to Coleman EHV line to Owensboro Municipal Utilities (OMU) Elmer Smith substation. This addition would loop the Wilson to Coleman 345 kV circuit through the Elmer Smith substation. While providing similar system benefits as the proposed substation, this alternative was not selected due to the high cost and additional right-of-way required for this new-terrain circuit. The 161 kV Wilson to Paradise (TVA) circuit was found to be an effective interconnection option. However, this costly improvement would require 16 miles of new-terrain 161 kV construction. In addition, it would be difficult to construct this facility in the desired time frame.

East Kentucky Power Cooperative (EKPC) had requested Big Rivers' participation in the construction of a 161 kV Wilson to Aberdeen (EKPC) interconnection. Consequently, this 26.79 mile new-terrain circuit was evaluated as part of the aluminum smelter load loss studies. While shown to be an effective interconnection option, this facility alone will not provide the required export capability. Additionally, EKPC is no longer pursing this interconnection. After considering the impact on land owners, the high cost, and EKPC's apparent lack of need, this alternative was not selected.

Since no generation will be added as part of the aluminum load loss scenario, no additional stability studies were completed. However, the stability studies completed as part of a previous generator interconnection study were reviewed. Short circuit analyses were completed and are described in Section V.

III. 2004 STUDIES

As part of the normal system planning process, multiple load loss scenarios have been studied. Various system improvement alternatives have been evaluated as part of this study process. In addition, a transmission service request (TSR) submitted by Big Rivers Power Supply (BRPS) on July 15, 2004 led to the completion of a system impact study. If approved, this yearly-firm TSR will provide a 450 MW path for generation sourced from the Big Rivers control area to a sink in the MISO system beginning in 2006. With the existing system (generation and load levels), Big Rivers control area generation is insufficient to source transactions that would fully utilize the TSR. Therefore, the TSR system impact study included a loss of load. The results of the system impact study are documented in the report attached as Appendix A. As the report shows, the focus of this study was to identify the system upgrades necessary to export all excess generation during peak load and light load conditions. The loss of either Century Aluminum alone or in combination with ALCAN was studied. A 2004 power flow model was used for the initial studies. A 2010 summer peak model from the 2003 NERC MMWG series was used for additional long-term studies.

As the studies progressed, a specific export scenario and timing constraint was provided by BRPS. This export scenario includes all excess generation exported with the loss of the Century Aluminum load. Since the original 2006 TSR start-date can not be accommodated, a delayed schedule was agreed upon. The revised schedule requires the facilities necessary to provide this export capability be constructed by late 2006 or early 2007. When cost, construction time, and the necessary new terrain rights-of-way required were considered, the Big Rivers to KU 345 kV interconnection was identified as the only viable alternative. As this option was pursued, contact was made with KU and the Midwest ISO. The intent was to prepare a coordinated study of the proposed interconnection. Big Rivers was unable to secure the participation of the Midwest ISO. However, KU did participate in joint studies. These studies are described in Section IV.

IV. 2006 STUDIES

After the studies progressed from a system impact study to an official request for an interconnection, additional studies were prepared by Big Rivers. KU also prepared studies and presented the results to Big Rivers. The results of these studies were documented in the attached memo (Appendix B). As the document shows, KU focused on scenarios in which all excess Big Rivers generation was exported during the loss of both aluminum smelters. Big Rivers evaluated the same scenarios with a model from the 2005 MMWG series. In addition, Big Rivers completed studies with the loss of only Century Aluminum. The studies showed the proposed interconnection to be an acceptable solution to alleviate overloads caused by additional power exports from the Big Rivers system.

As previously discussed, a 345 kV loop in and out of the OMU Elmer Smith Substation was evaluated as an alternative to the proposed KU interconnection. This option was studied as part of a previous generator interconnection study. Cost estimates related to this option were updated and are included in Appendix D. While comparable to the proposed KU interconnection option when the effectiveness of the alternative is considered, the alternative requires 8.5 miles of new-terrain 345 kV double-circuit construction. After considering the greater impact on land owners, as well as the significantly greater cost ($13,700,000 versus $6,600,000), the decision to not pursue this option was made. Cost estimates for the previously discussed Wilson to Paradise 161 kV interconnection were also reviewed and are attached in Appendix D. Again, after considering the land owner impact from this new-terrain construction and the higher cost ($8,840,000 versus $6,600,000), a decision to not pursue this option was made.

V. SHORT CIRCUIT ANALYSIS

A short-circuit study was completed for the Big Rivers 2006 electric system. The intent of the study was to determine if the replacement of any circuit breakers would be required as a result of the proposed interconnection. The study results are shown in Appendix C. Based on these results, no breaker replacement projects are proposed.

VI. CONCLUSION

The proposed interconnection with KU will increase the Big Rivers export capability and will allow the excess control area generation to be exported in the event of the loss of the Century Aluminum load. Consequently, the 450 MW annual firm TSR from BRPS can be accepted and will commence upon the interconnection completion in 2007. The proposed interconnection can be constructed within the desired time-frame and with minimal impact to land owners. When the cost, time of construction, overall robustness, and environmental impacts are all considered, the proposed KU interconnection was judged the superior alternative.

APPENDIX A: SYSTEM IMPACT STUDY FOR BIG RIVERS POWER SUPPLY

Big Rivers
Electric Corporation

Memorandum

System Impact Study - Alternatives to Increase Export Capability 12/17/04 Summary of Studies

Big Rivers Power Supply requested 450 MW of additional transmission for the year 2006. The primary need for the additional transmission is to ensure that excess generation that may be available due to the loss of one or both aluminum smelters can be exported off-system. Two improvement options have been studied. The first option includes a new 345 kV switching station east of Owensboro. This station will interconnect the existing Wilson to Coleman 345 kV circuit to the existing Smith (OMU) to Hardin County (KU) 345 kV circuit. The second alternative includes a new 161 kV Wilson to Aberdeen (EKPC) circuit.

Both options were studied with traditional power flow studies with maximum generation output and single contingency conditions (i.e. can all excess power be exported with the option under study?). In addition, ATC studies based on linear extrapolation were completed. In these studies, a 40 MW test transfer is simulated. Transfer factors calculated with the 40 MW test level are used to find the transfer level at which a facility limit is reached. These studies look beyond generation limitations. Therefore, results may be inaccurate beyond the export levels for which actual generation is available.

The study results of both options are described below:

345 kV Owensboro Substation: As described above, this option includes a new 345 kV switching station east of Owensboro. The new station will interconnect the existing Wilson to Coleman 345 kV circuit to the existing Smith (OMU) to Hardin County (KU) 345 kV circuit. No additional transmission construction is expected for Big Rivers. However, improvements that may be required by KU are unknown at this time. A MISO interconnection study and transmission deliverability study would be required to determine the MISO facility requirements.

Peak Load Results: ATC studies showed a total export capability of 569 MW (well above the 155 MW net export level supported by the available generation). Traditional power flows studies showed no overloads with a maximum generation dispatch and each single contingency outage.

Off-Peak Load Results: ATC studies showed a total export capability of 734 MW (well above the available generation). This compares to an ATC of 624 MW with no system improvements. Traditional power flows studies showed no overloads with a maximum generation dispatch and each single contingency outage.

No Century Results: ATC studies showed a total export capability of 900 MW to 1000 MW (well above the 625 MW net export supported by the available generation). This compares to an ATC of 300 MW to 550 MW with no system improvements. Traditional power flows studies showed no overloads with a maximum generation dispatch and each single contingency outage.

No Smelters Results: ATC studies showed a total export capability of 924 MW (less than the 960 MW net export supported by the available generation). Traditional power flows studies showed no overloads with an export level of approximately 900 MW, but did show overloads with full generation dispatch.

Overall: Due to the study method limitations, the ATC values vary greatly with the generation dispatch and other assumptions. However, both the "no Century" and "no smelters" studies resulted in an ATC of approximately 900 MW. Traditional power flow studies showed that all excess generation could be exported with peak loads, off-peak loads, and with Century Aluminum at 0 MW (approximately 620 MW net export). The excess generation available with both smelters at 0 MW (approximately 960 MW) cannot be exported with this option. If the already sold 460 MW is subtracted from a 900 MW export capability, the resulting ATC is 440 MW. This would allow most or all of the requested ATC to be accepted.

161 kV Wilson to Aberdeen (EKPC) Circuit: As described above, this option includes the construction a new 161 kV Wilson to Aberdeen (EKPC) circuit approximately 27 miles in length.

Peak Load Results: ATC studies showed a total export capability of 655 MW (well above the available generation). Traditional power flows studies showed no overloads with a maximum generation dispatch and each single contingency outage.

Off-Peak Load Results: ATC studies showed a total export capability of 827 MW (well above the available generation). This compares to an ATC of 624 MW with no system improvements. Traditional power flows studies showed no overloads with a maximum generation dispatch and each single contingency outage.

No Century Results: ATC studies showed a total export capability of 670 MW to 900 MW (above the 625 MW net export supported by the available generation). This compares to an ATC of 300 MW to 550 MW with no system improvements. Traditional power flows studies showed no overloads with a maximum generation dispatch and each single contingency outage. However, during an outage of the Wilson to Green River circuit, the Coleman to Newtonville loading was approximately 100%. This indicates that the maximum export capability is approximately 625 MW.

No Smelters Results: ATC studies showed a total export capability of 730 MW (less than the 960 MW net export supported by the available generation). Traditional power flows studies showed overloads with an export level of approximately 900 MW. The export level was not reduced to find the actual transfer limit. However, it seems reasonable to assume an export level similar to the "no Century" studies would be found.

Overall: *Due to the study method limitations, the ATC values vary greatly with the* generation dispatch and other assumptions. However, the increase in ATC (above that with no system improvements) appears to be 200 MW to 350 MW (200 MW seems to be a safe assumption for ATC increase resulting from this improvement). Traditional power flow studies showed that all excess generation could be exported with peak loads, off-peak loads, and with Century Aluminum at 0 MW (approximately 620 MW net export). The excess generation available with both smelters at 0 MW (approximately 960 MW) cannot be exported with this option.

Summary

Either option will allow all excess generation to be exported off-system with both smelters in operation during peak or off-peak load~~s.~~ conditions.

Either option will allow all excess generation to be exported off-system with Century Aluminum at 0 MW during peak conditions.

With both Century and Alcan at 0 MW, neither option will allow all excess generation to be exported.

The traditional power flow studies show the 345 kV option to be a more robust system improvement for Big Rivers.

Based on both the "no Century" and "no smelter" study results, it appears that the 450 MW request could be accepted contingent upon construction of the 345 kV station. With the Wilson to Aberdeen interconnection, approximately 200 MW could be accepted. However, the deliverability of this power into MISO or TVA is unknown at this time.

Transmission Reservation Detail 70208638 STUDY

Seller	Source Sink	POR POD	Request Type	Start	Stop	MW Req	MW Grant	Bid Price	Offer Price	Ceiling Price	Price Unit
BREC	BREC [redacted]	BREC MISO	ORIGINAL	2006-01-01 00:00 CS	2007-01-01 00:00 CS	450		11.8000		11.8000	$/KW-Year
Path: E/BREC/BREC-MISO//											

Service Code	Increment	Class	Type	Period	Window	Subclass
FYLFP	YEARLY	FIRM	POINT_TO_POINT	FULL_PERIOD	FIXED	

Preconfirmed: No	**Competing:** No	**Negotiated:** No	**Nerc Priority:** 7	**Affiliate:** No

Reservation Profile

Start Date	Stop Date	MW Req	MW Grant	MWH	Bid Price	Offer Price
2006-01-01 00:00 CS	2007-01-01 00:00 CS	450		3942000.00	11.80	
			Profile Total:	3942000.00		

Times		References	
Queued	2004-07-15 15:02:01 CD	**Deal**	
Updated	2004-07-15 15:02:52 CD	**Sale**	
Response		**Posting**	
		Request	
Impacted	0	**Reassigned**	
		Seller	
		Related	

Comments

Status	
Seller	
Provider	
Customer	

Status Notification	
Anc-Service-Link	

Customer: BRPS		Seller: BREC	
Name	BYeary	**Name**	CBradley
Phone	(270)827-2561	**Phone**	2708272561
Fax	(270)827-2101	**Fax**	2708272101
E-mail	byeary@bigrivers.com	**E-mail**	cbradley@bigrivers.com

APPENDIX B: 2006 STUDY RESULTS

Big Rivers
Electric Corporation

Memorandum

To: Travis Housley

From: Chris Bradley

CC: David Crockett & Bob Warren

Date: 03/22/06

Re: Big Rivers – LGEE 345 kV Interconnection Study Update

E.ON U.S. has studied the proposed interconnection and submitted the results to Big Rivers (see the attachment). The E.ON U.S. study included an evaluation of the proposed interconnection with the loss of both aluminum smelters. In addition, E.ON U.S. evaluated the system with and without the addition of a Wilson to Aberdeen (EKPC) 161 kV interconnection. The following is a discussion of the attached E.ON. U.S. results:

Column A: With no new interconnections and both smelters in operation, no overloads were identified by E.ON. U.S.

Column B: With no new interconnections and both smelter loads at 0 MW, significant E.ON. U.S. and Big Rivers overloads were identified by E.ON. U.S.

Column C: With no new interconnections and both smelter loads at 0 MW, significant E.ON. U.S. and Big Rivers overloads were identified by Big Rivers (the Big Rivers study results were consistent with the E.ON. U.S. study results).

Column D: With the addition of the proposed 345 kV interconnection and both smelter loads at 0 MW, E.ON. U.S. and Big Rivers overloads were identified by E.ON. U.S.

Column E: With the addition of both the proposed 345 kV interconnection and the Wilson to Aberdeen (EKPC) 161 kV interconnection (both smelter loads at 0 MW), two E.ON. U.S overloads were identified. These overloads can be eliminated with terminal improvements and a 1.3 mile 138 kV line rebuild.

Column F: These results, when compared to Column E, show no significant impact is expected as a result of the Trimble County Unit 2 generation addition.

Column G: With the addition of only the Wilson to Aberdeen (EKPC) 161 kV interconnection and both smelter loads at 0 MW, E.ON. U.S. and Big Rivers overloads were identified by E.ON. U.S.

Column H: With the addition of only the Wilson to Aberdeen (EKPC) 161 kV interconnection and both smelter loads at 0 MW, E.ON. U.S. and Big Rivers overloads were identified by Big Rivers (the Big Rivers study results were consistent with the E.ON. U.S. study results).

Column I: These results, when compared to Column G, show no significant impact is expected as a result of the Trimble County Unit 2 generation addition.

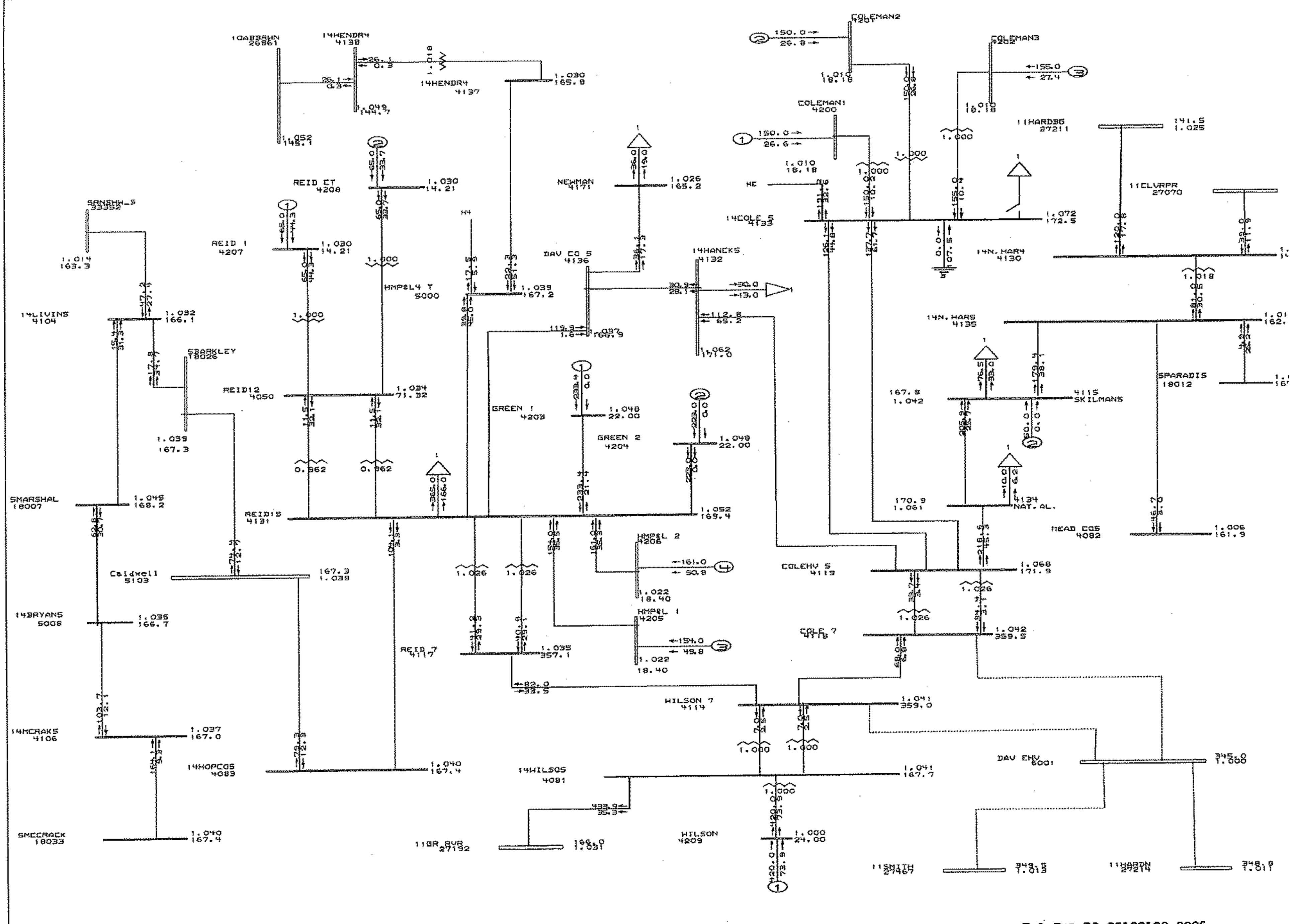
Column J: With no new interconnections and Century Aluminum at 0 MW, significant E.ON. U.S. and Big Rivers overloads were identified by Big Rivers.

Column K: With the addition of the proposed 345 kV interconnection and Century Aluminum at 0 MW, no E.ON. U.S. or Big Rivers overloads were identified by Big Rivers.

In general, the Big Rivers study results are consistent with the E.ON U.S. study results. Each show the addition of both interconnections will eliminate all but two overloads with the loss of both aluminum smelters. In addition, the Big Rivers identified no overloads with the proposed interconnection addition and the loss of Century Aluminum.

BREC Update of E.ON U.S. Document
4/17/06 CSB

FACILITY	CONTINGENCY	Rating (MVA)		A	B	C	D	E	F	G	H	I	J	K
			YEAR	2009 S	2009 S	2010 S	2009 S	2009 S	2009 S	2009 S	2010 S	2009 S	2006 S	2006 S
			EKPC TIE	NO	NO	NO	NO	YES	YES	YES	YES	YES	NO	NO
			345 TIE	NO	NO	NO	YES	YES	YES	NO	NO	NO	NO	YES
			TC2 + OUTLET	NO	NO	NO	NO	NO	YES	NO	NO	YES	NO	NO
			EXPORT		800+	882	800+	800+	800+	800+	882	800+	565	565
			CENTURY	485	0	0	0	0	0	0	0	0	0	0
			ALCAN	365	0	0	0	0	0	0	0	0	365	365
			STUDIED BY	E.ON U.S.	E.ON U.S.	BREC	E.ON U.S.	E.ON U.S.	E.ON U.S.	E.ON U.S.	BREC	E.ON U.S.	BREC	BREC
BREC overloads alleviated by Interconnection														
14COLE 5 161.00-14NATAL5 161.00 1	14WILSO5 161-GR RVR 161 1	265		125.1	294.2	291.7					228.7		334.7	152.9
14REID 5 161.00-14HOPCO5 161.00 1	14WILSO5 161-GR RVR 161 1	265		66.3	357.3	390.5					280.0		215.4	
14SKILM5 161.00-14NATAL5 161.00 1	14WILSO5 161-GR RVR 161 1	265		116.5	282.0	279.2					217.3		321.3	141.4
5BARKLEY 161.00-14HOPCO5 161.00 1	14WILSO5 161-GR RVR 161 1	265		40.1	342.5	325.6					235.5			
BREC overloads reduced but not alleviated by Interconnection														
14WILSO5 161.00-GR RVR 161.00 1	10NTVL16 161-14COLE 5 161 1	558		266.7	711.7	671.2							488.7	297
14WILSO5 161.00-GR RVR 161.00 1	21-ABD 161-14WILSO5 161 1	558		N/A		N/A				608.0	574.2	601.7		
14WILSO5 161.00-GR RVR 161.00 1	14WILSO7 345-BRtoKU 345 1	558		N/A		N/A	575.6							427.3
10NTVL16 161.00-14COLE 5 161.00 1	14WILSO5 161-GR RVR 161 1	265		65.7	558.8	516.9				381.9	351.5		346.5	101.2
10NTVL16 161.00-14COLE 5 161.00 1	HARDN CO 345-KUtoBR 345 1	265		N/A		N/A	292.4					382.7		137
10NTVL16 161.00-14COLE 5 161.00 1	21-ABD 161-14WILSO5 161 1	265									277.5			
10NTVL16 161.00-10NTVL 13 138.00 T1 & T2	14WILSO5 161-GR RVR 161 1	176				182.6					128.7			
14COLE 5 161.00-14NATAL5 161.00 1	10NTVL16 161-14COLE 5 161 1	265											302.2	160.4
E.ON U. S. overloads alleviated by Interconnection														
CLOVRPRT 138.00-10NTVL13 138.00 1	14WILSO5 161-GR RVR 161 1	275		137.6	333.7	314.8							204.7	80.6
GR RV ST 138.00-GR RVR 138.00 1	10NTVL16 161-14COLE 5 161 1	176		13.8	187.3									
SHREWSBU 138.00-BONNI KU 138.00 1	SHREWSBU 138-LEITCHF 138 1	137		91.2	139.8									
SHREWSBU 138.00-LEITCHF 138.00 1	SHREWSBU 138-BONNI KU 138 1	92		78.6	98.6									
SMITH 345.00-SMITH 138.00 1	HARDINSB 138-HARDN CO 138 1	308		246.9	356.9					331.9				
GR RVR 161.00-GR RVR 138.00 3	GR RVR 161-GR RVR 138 2	129		90.7	166.9					135.2				
GR RVR 161.00-GR RVR 138.00 2	GR RVR 161-GR RVR 138 3	120		85.0	157.1					127.1				
GR RVR 161.00-GR RVR 138.00 1	GR RVR 161-GR RVR 138 3	120		81.3	150.3					121.7				
OHIO CO 138.00-GR RVR 138.00 2	OHIO CO 138-GR RVR 138 1	169		154.0	213.7		177.2			191.3		187.2	183.8	164.2
OHIO CO 138.00-GR RVR 138.00 1	OHIO CO 138-GR RVR 138 2	177		158.5	207.6					185.9		181.8	178.6	159.5
E.ON U.S. overloads created by Interconnection														
CLOVRPRT 138.00-GR RV ST 138.00 1	HARDN CO 345-KUtoBR 345 1	223		161.3	198.1		249.6							147.3
GR RV ST 138.00-GR RVR 138.00 1	14WILSO5 161-GR RVR 161 1	176		98.5	118.3		184.8							
HARDINSB 138.00-HARDN CO 138.00 1	HARDN CO 345-KUtoBR 345 1	247		174.1	235.9		257.0							208.2
GR RV ST 138.00-SMITH 138.00 1	HARDN CO 345-KUtoBR 345 1	263		227.4	229.4		318.9	287.5	284.1					201.1
HARDN CO 138.00-ETOWN 138.00 1	HARDN CO 345-BROWN N 345 1	247		151.8	214.7		317.2	295.4	310.0					235.8



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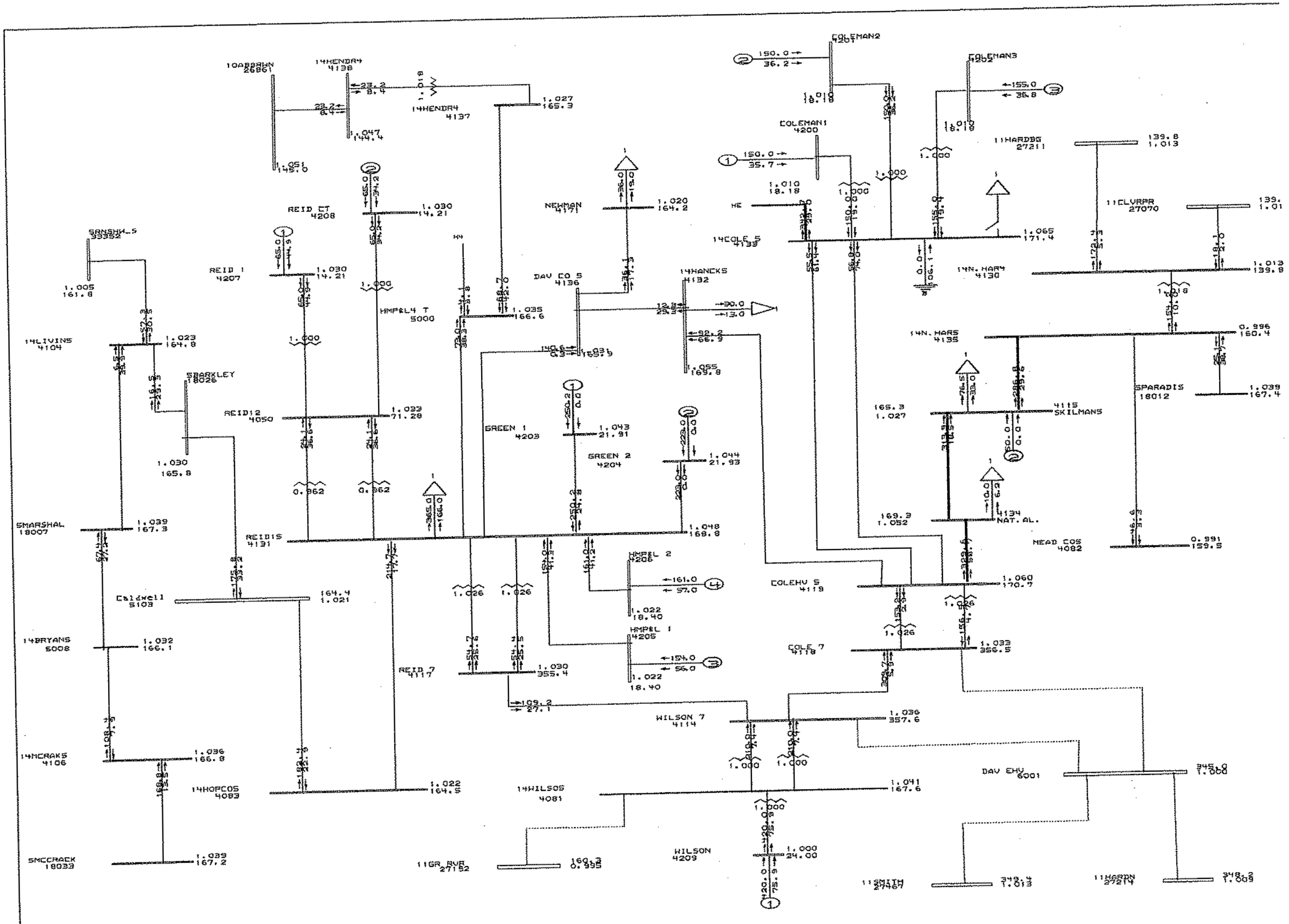

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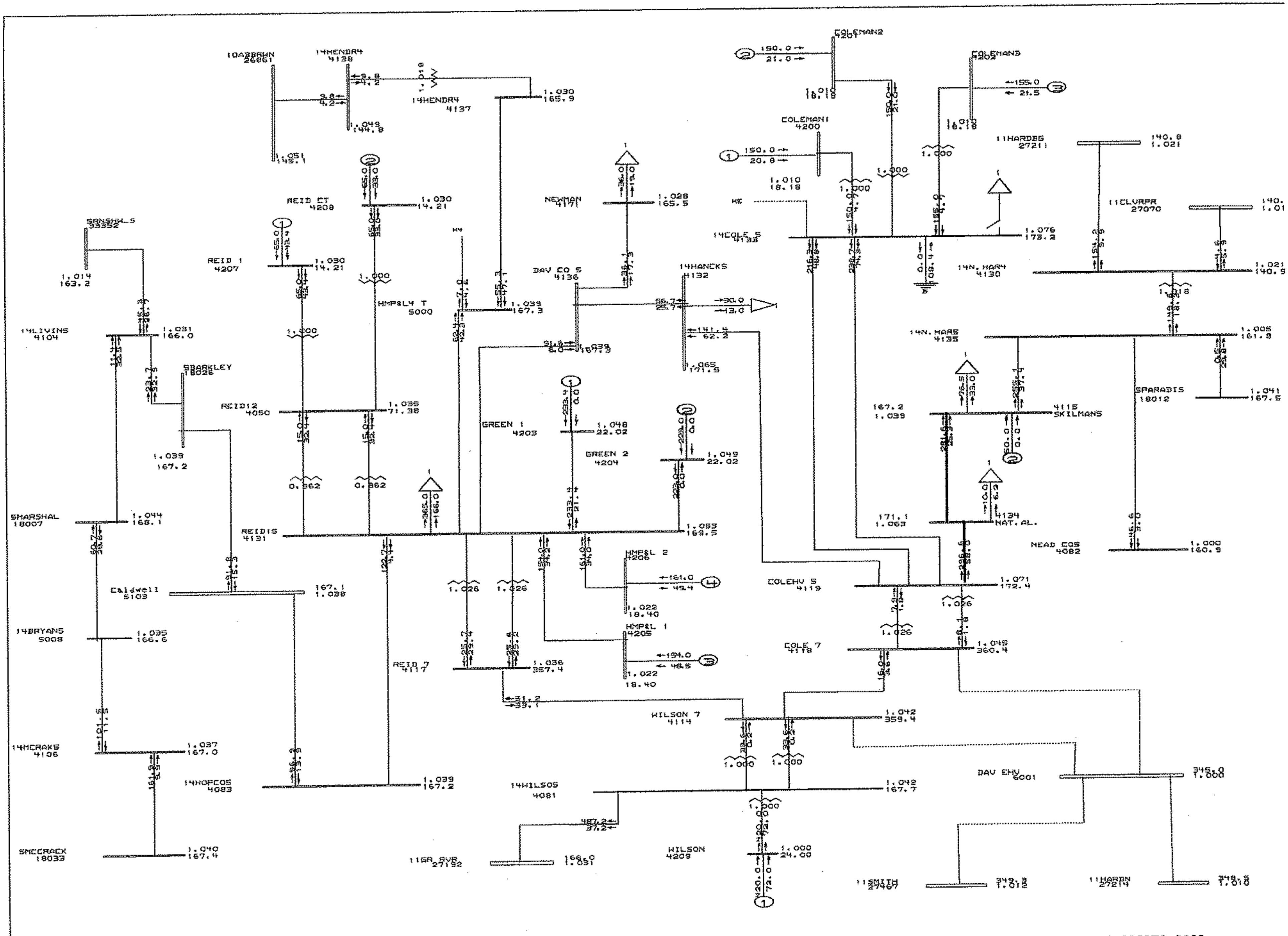

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PSLF Progr

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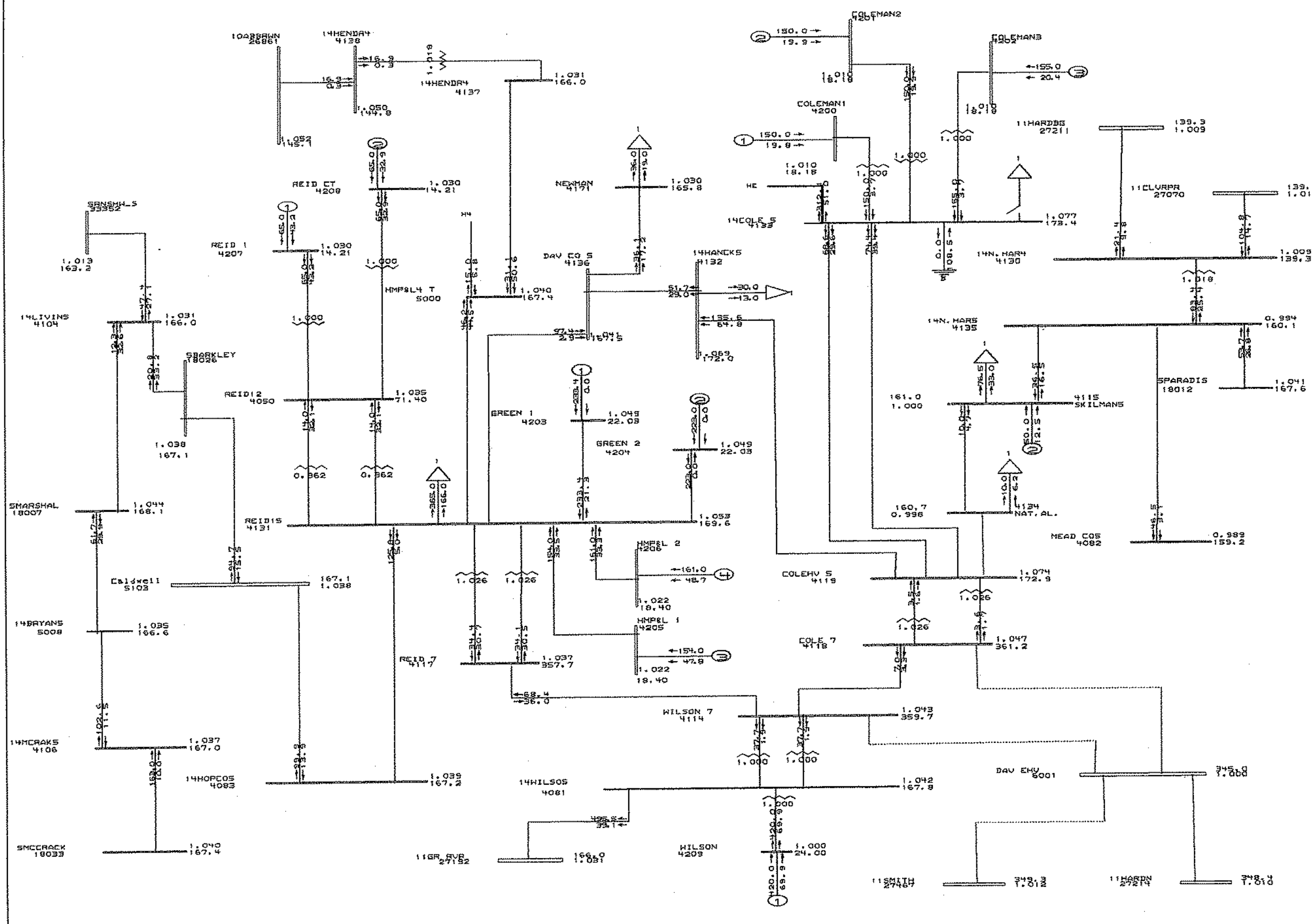

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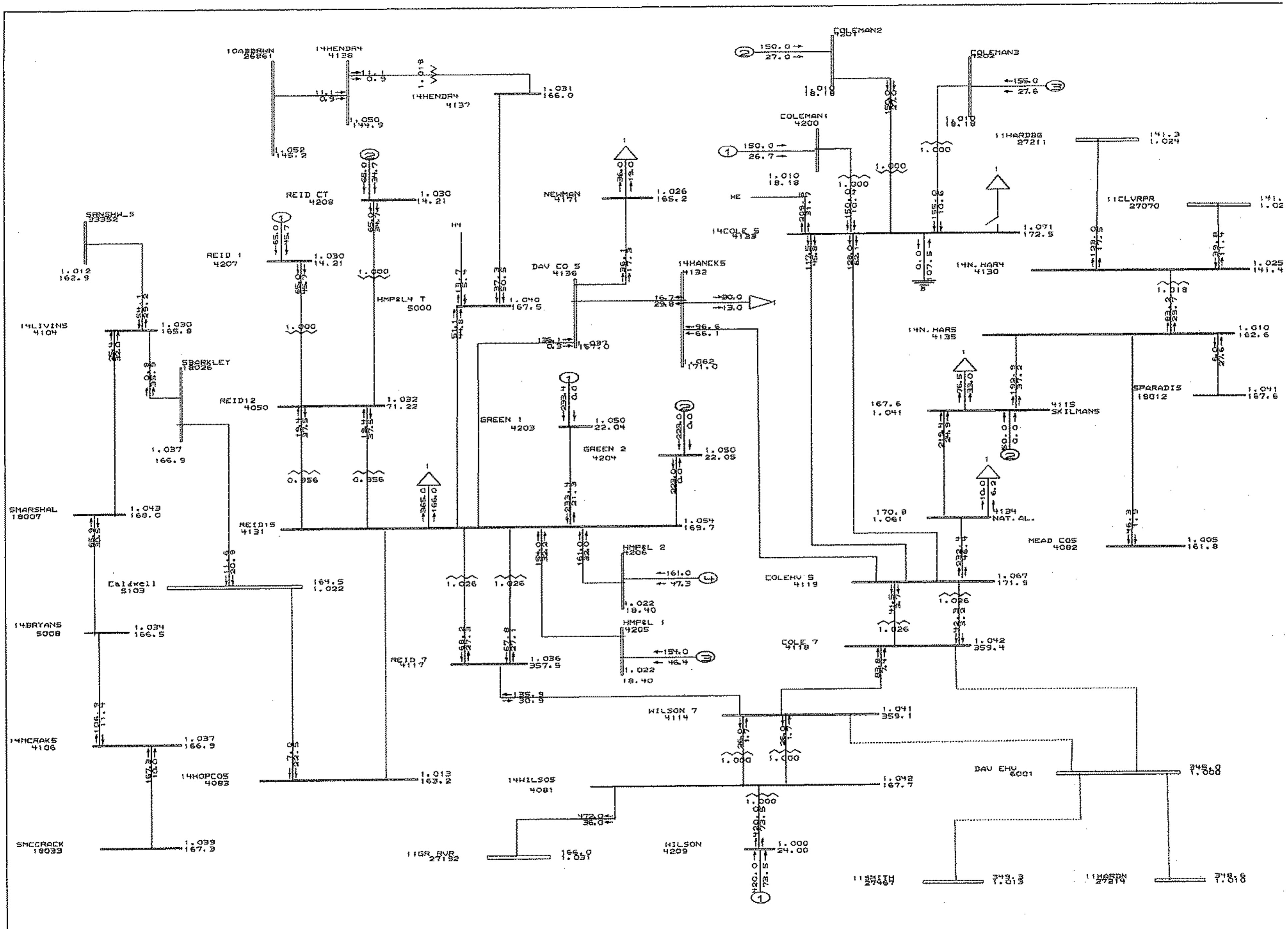

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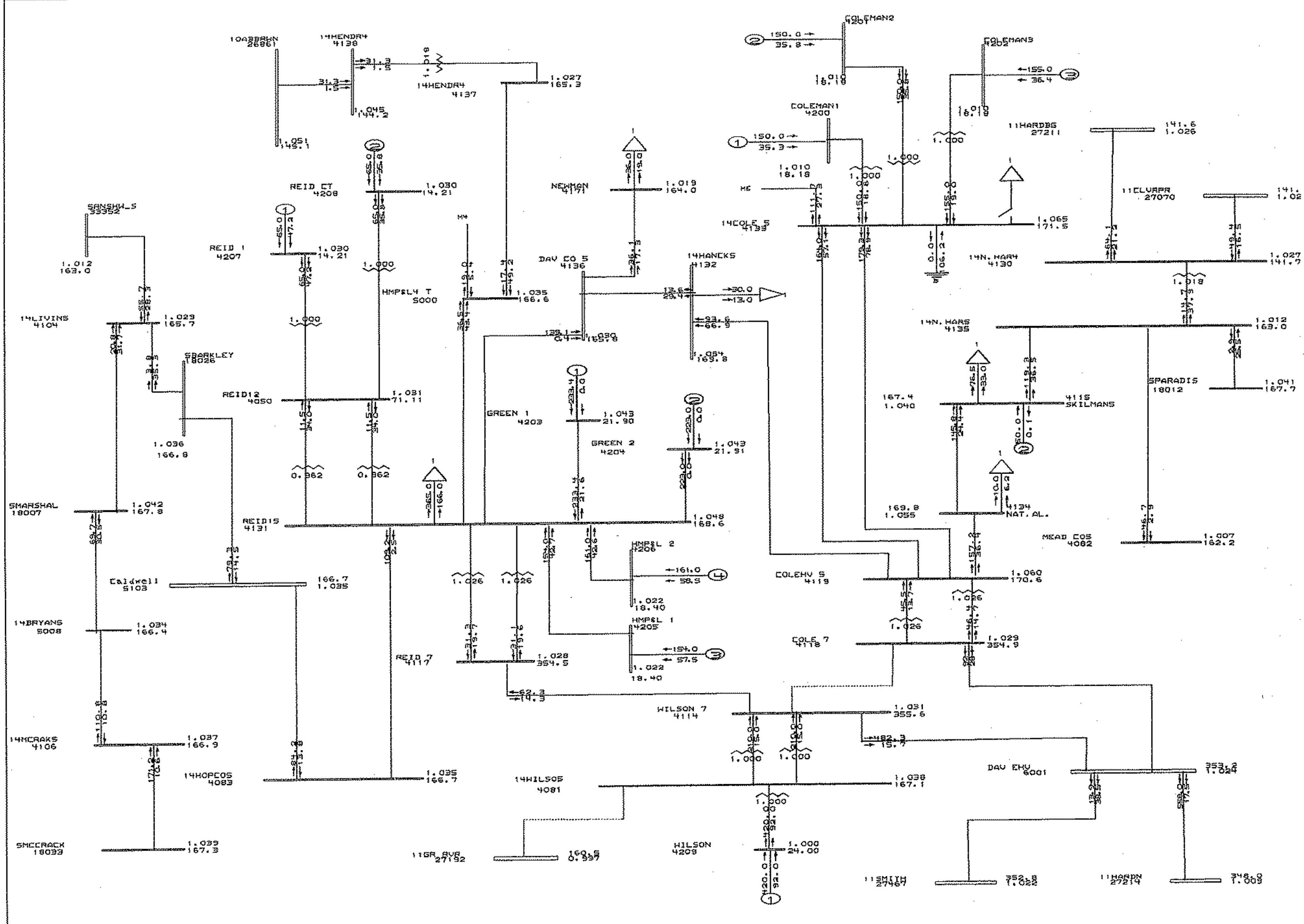

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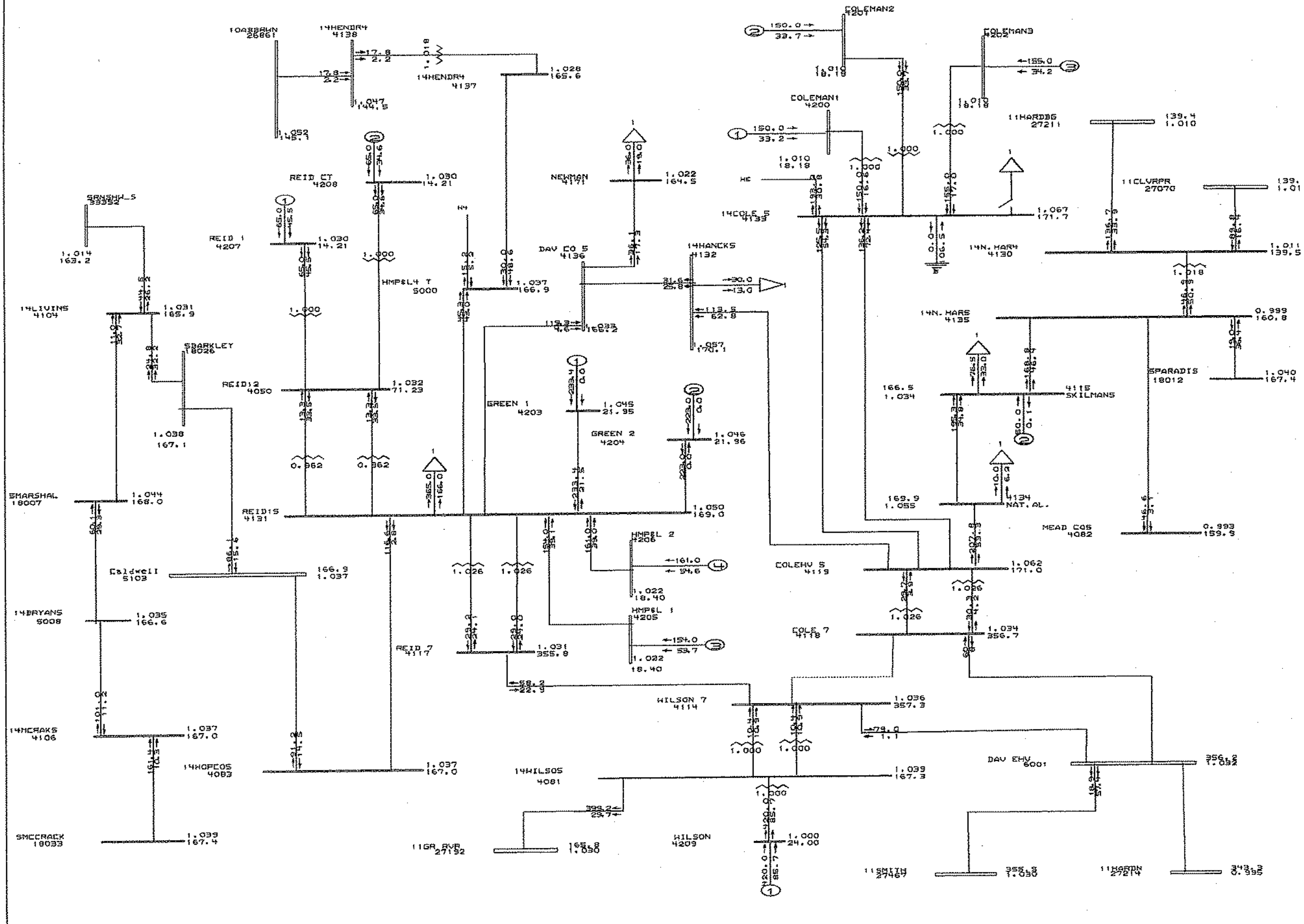

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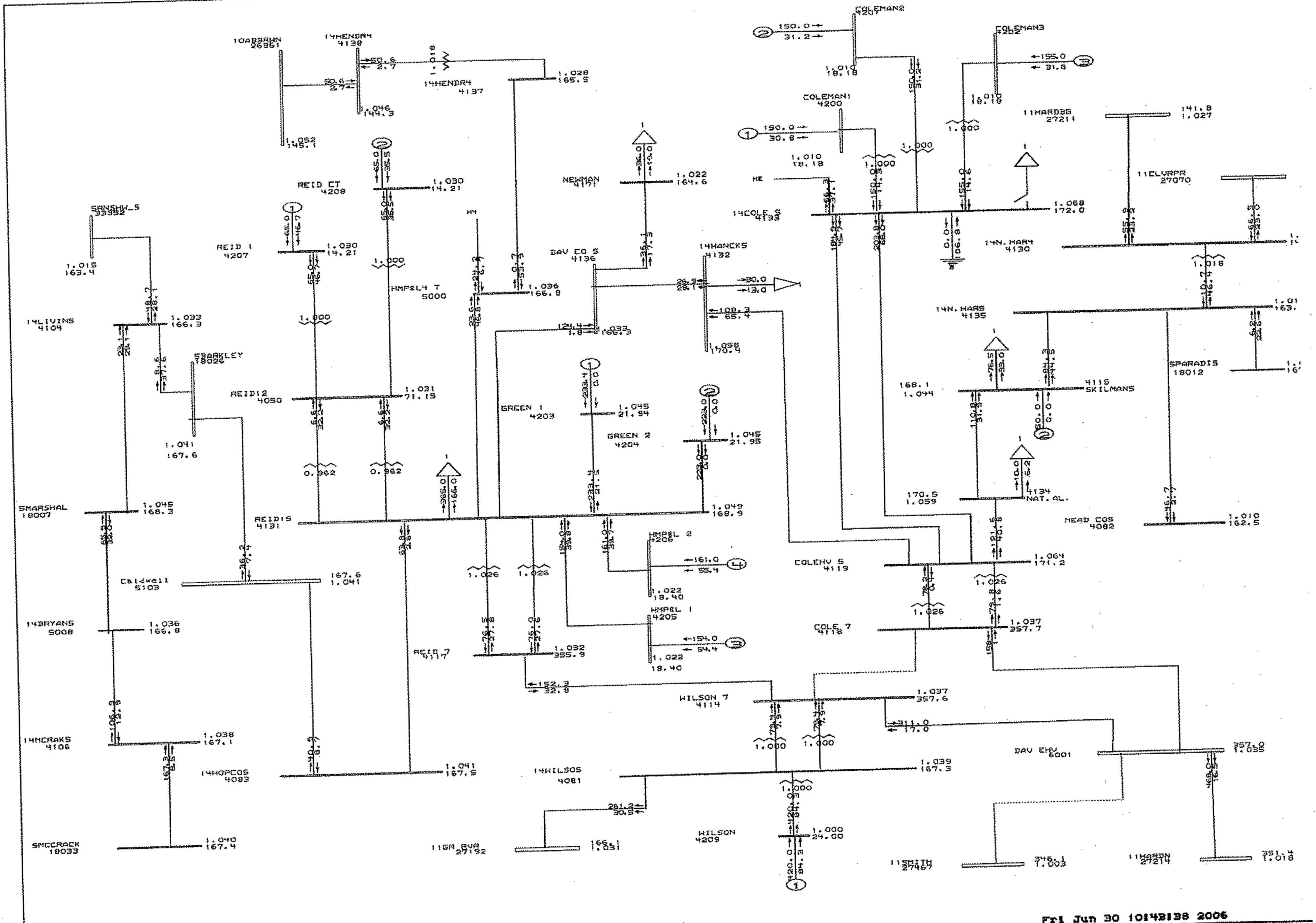

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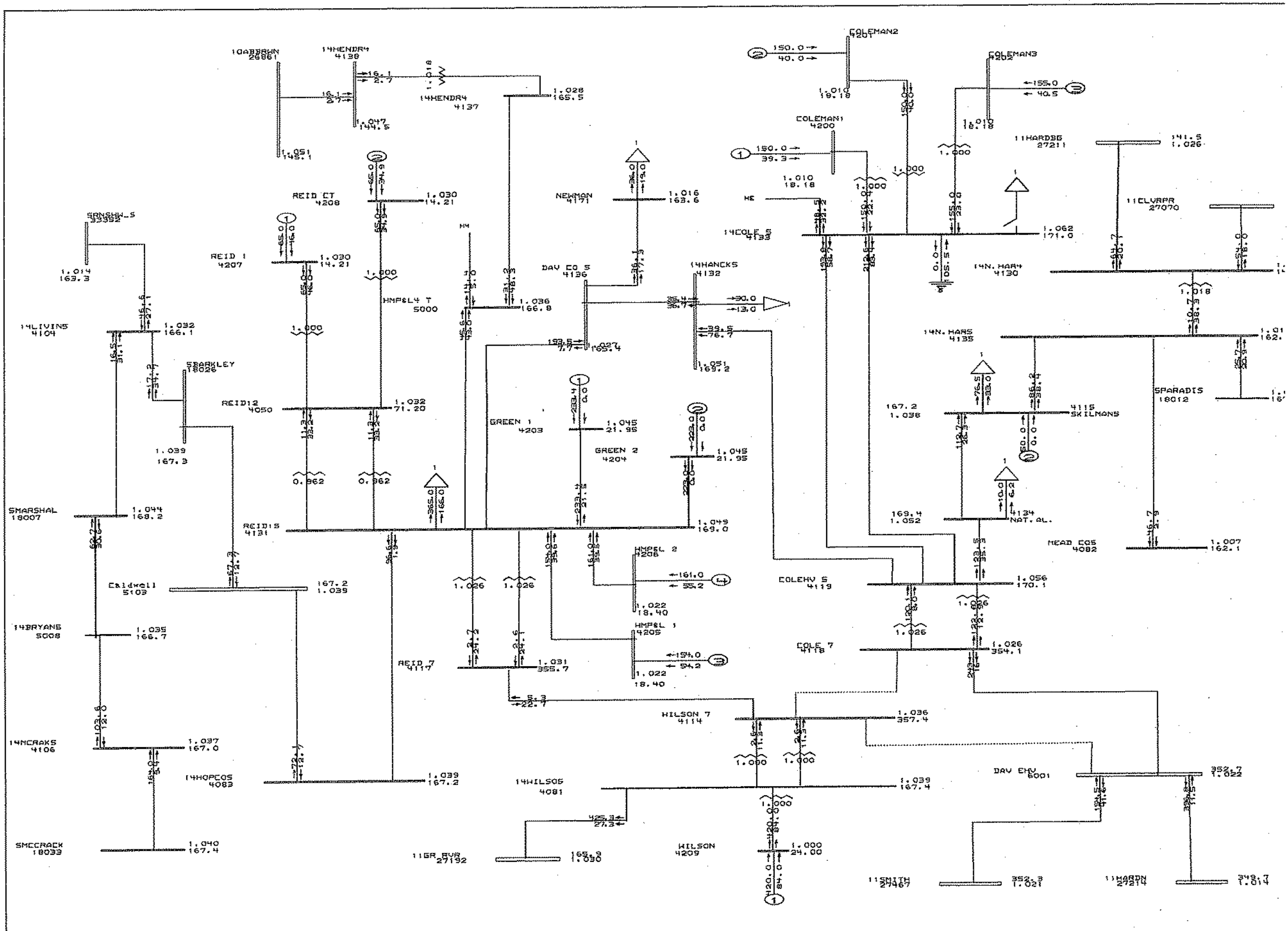

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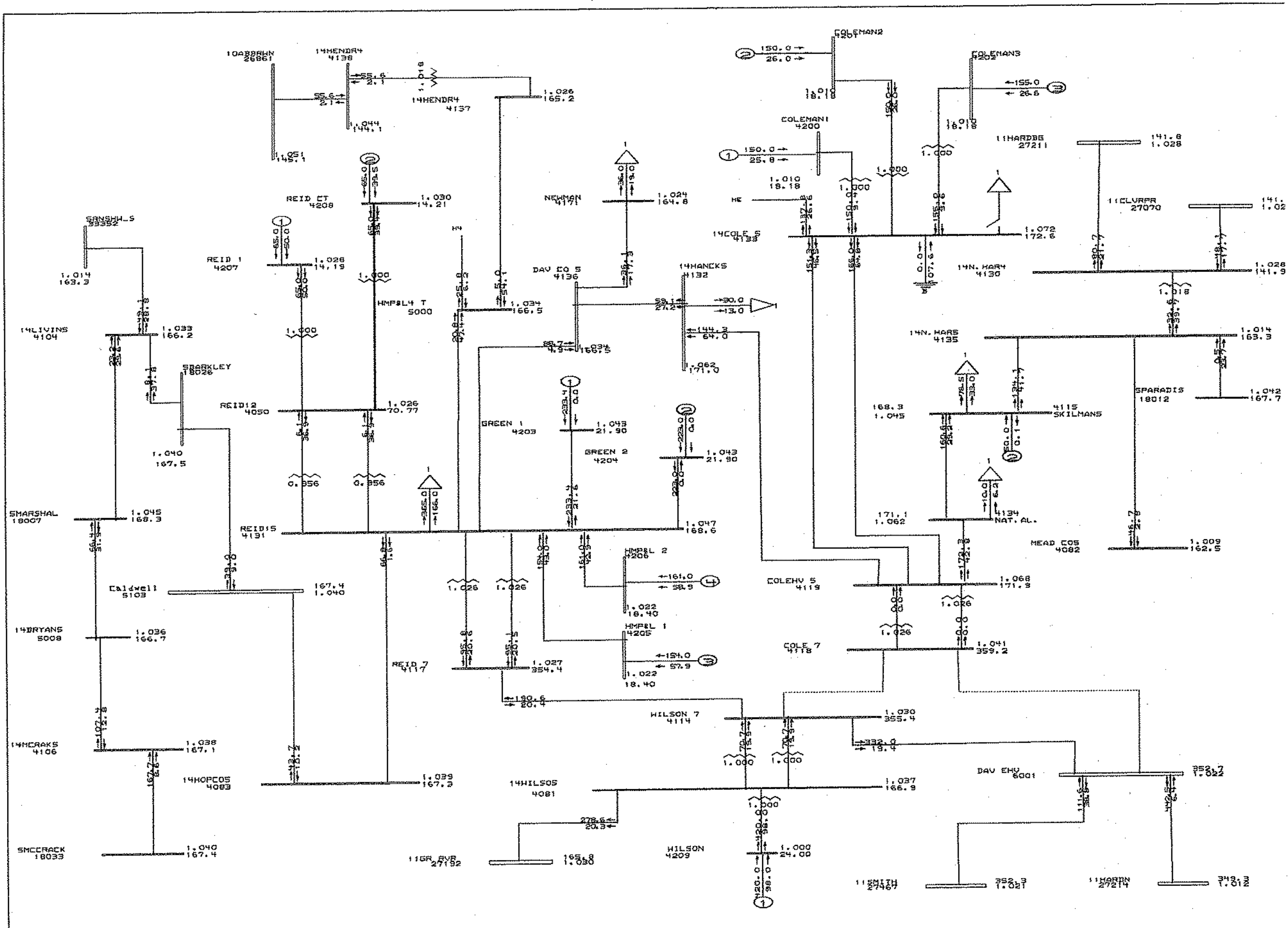
Rating -



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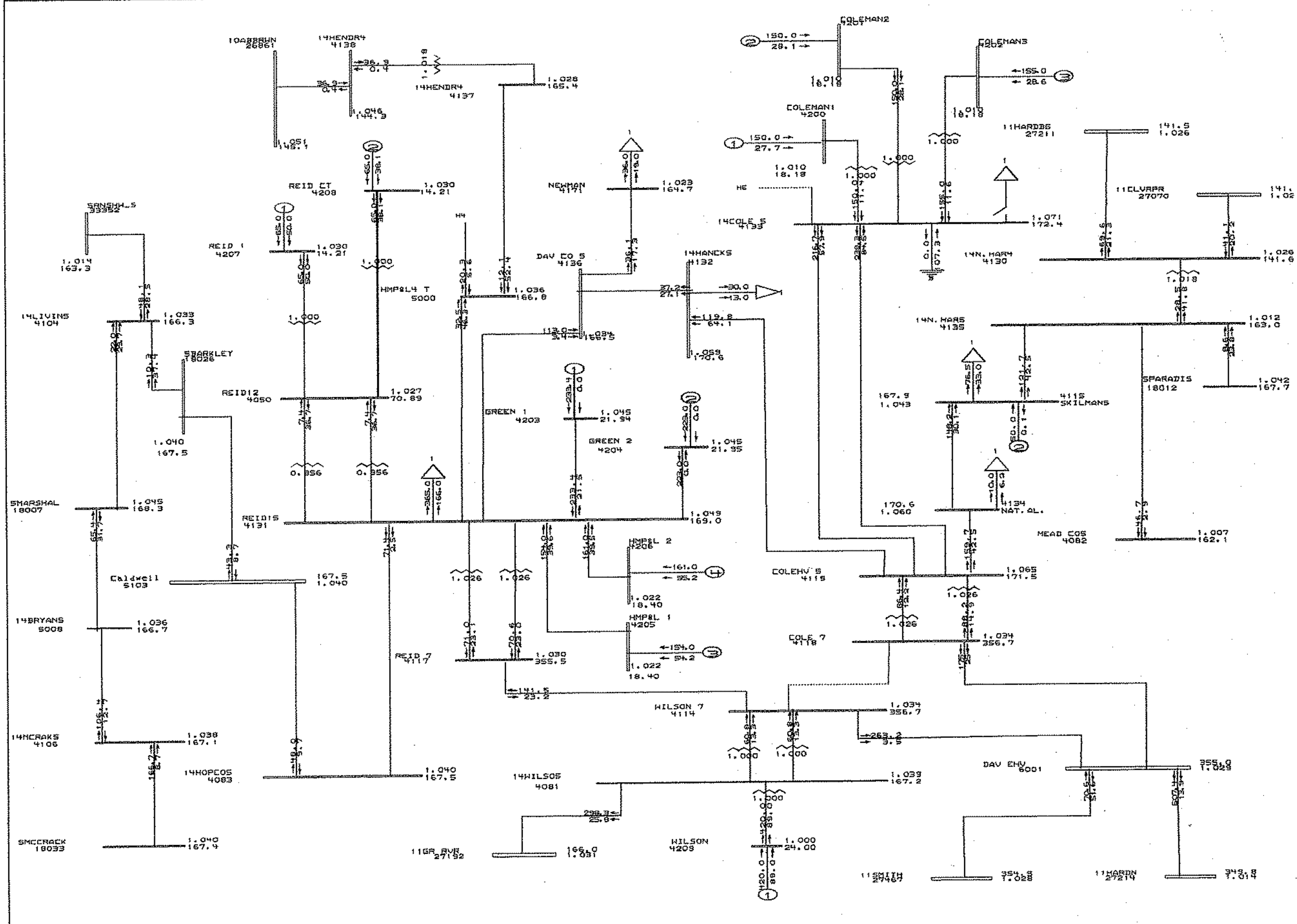

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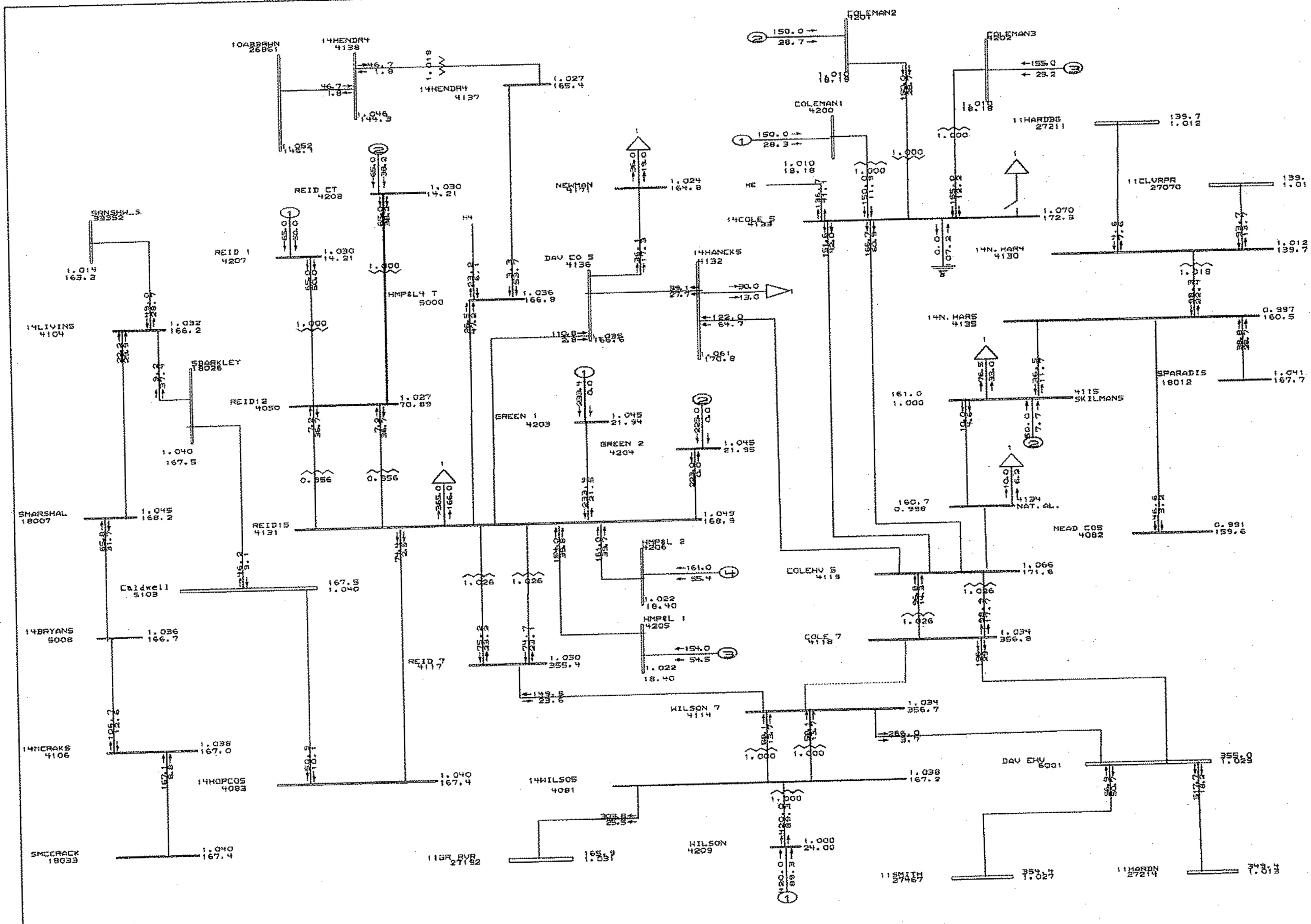

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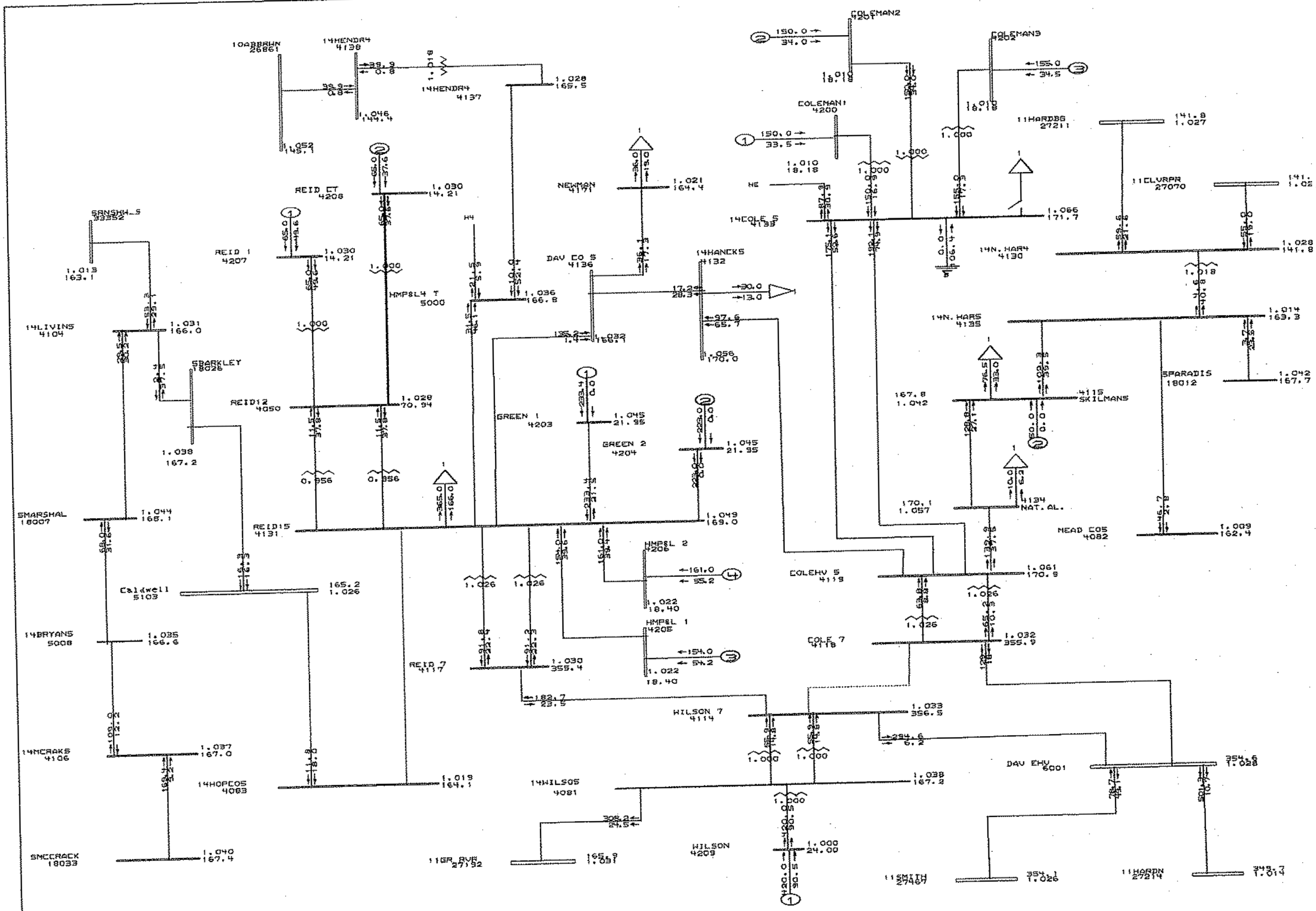

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2005 SERIES, NERC/MMWG BASE CASE LIBRARY

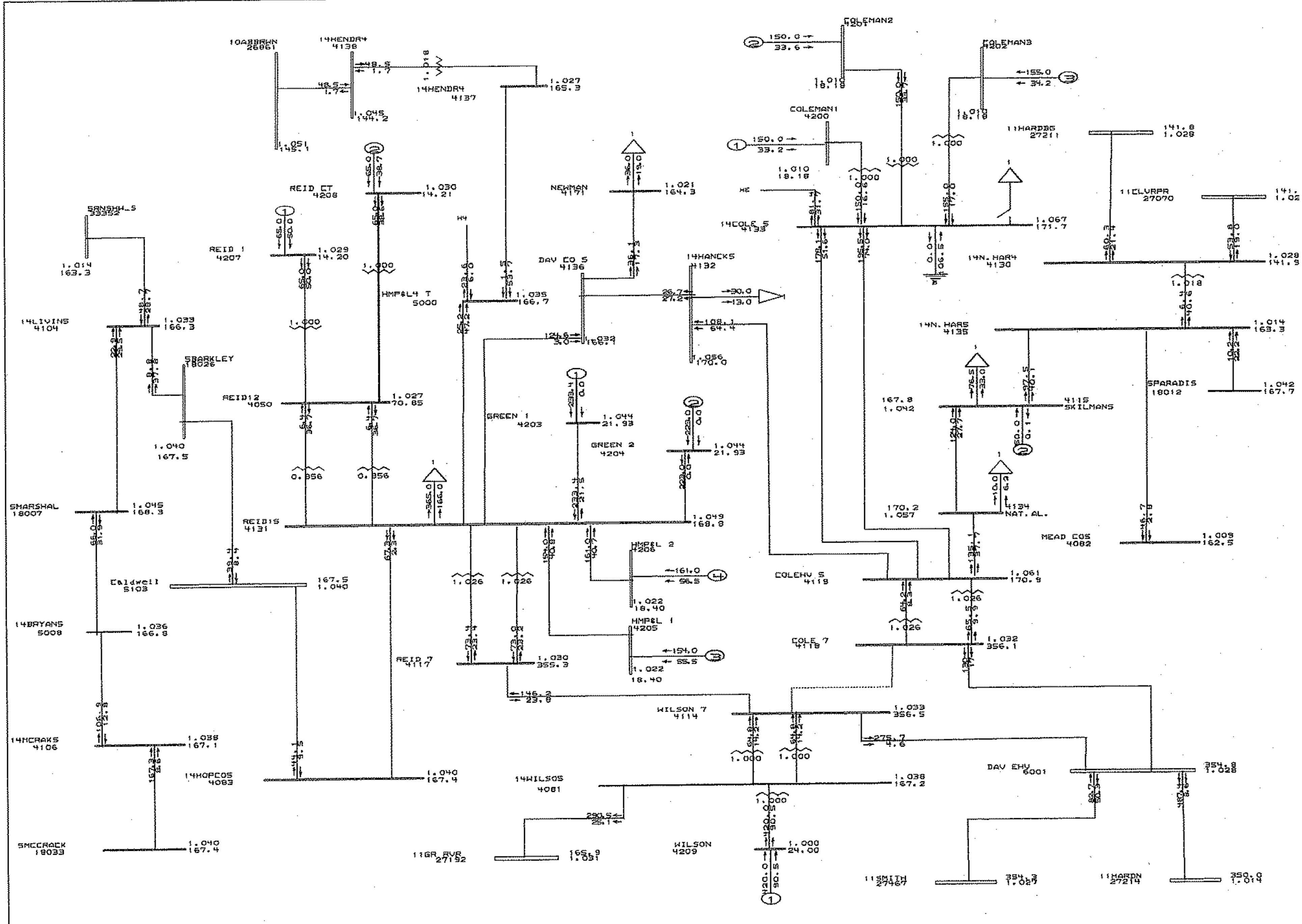
2006 SUMMER FINAL

Reid to Hopkins Co. out

PSLF Progra

bulk.drw

Rating =



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APPENDIX C: SHORT CIRCUIT ANALYSIS

Big Rivers
Electric Corporation

Memorandum

To: Bob Warren

From: Chris Bradley

CC:

Date: 04/24/06

Re: Big Rivers – E.ON. U.S. 345 kV Interconnection – Short Circuit Results

---

Short circuit studies to evaluate the impact of the proposed 345 kV Big Rivers to E.ON. U.S interconnection have been completed. A short circuit model supplied by ECAR in 2005 was used to perform studies with and without the addition. The results were also bench marked by comparing the ECAR model results (without the interconnection) to the Big Rivers short circuit model results. The results are summarized on the first attachment with more detailed results included on subsequent attachments.

Short Circuit Study Results
4/24/2006
CSB

FAULT CURRENT (AMPS) AT EACH FAULT LOCATION

Fault Location	ECAR Model without Interconnection		ECAR Model with Interconnection		BREC Model without Interconnection	
	Three Phase	Single Line-to-Ground	Three Phase	Single Line-to-Ground	Three Phase	Single Line-to-Ground
Wilson 345 kV	9,094	9,837	11,223	11,715	9,059	9,909
Coleman EHV 345 kV	7,734	8,139	9,632	9,774	7,544	7,990
Daviess Co. EHV 345 kV	N/A	N/A	11,719	11,309	N/A	N/A
Elmer Smith 345 kV	4,543	4,194	10,135	9,300	N/A	N/A
Elmer Smith 138 kV	16,285	17,965	18,293	20,275	N/A	N/A
Green River Steel 138 kV	15,998	16,911	17,797	18,802	N/A	N/A
Elmer Smith 69 kV	20,975	22,791	22,477	24,413	N/A	N/A
Hardin Co. 345 kV	6,427	5,972	8,354	7,251	N/A	N/A

APPENDIX D: PRESENT WORTH ANALYSIS

PROPOSED DAVIESS COUNTY EHV SUBSTATION (2006)

	YEAR	TRANS. INVESTMENT 2006 $'s	TRANS. $ INFLATED 3.00%	SUBSTATION INVESTMENT 2006 $'s	SUB $ INFLATED 3.00%	TRANS. DEPR 2.86%	SUBSTATION DEPR 2.22%	INTEREST 5.75%	TRANS. O&M 6.63%	STATION O&M 4.30%	ANNUAL COST IN NOM. $	PRESENT WORTH (2006)
1	2006	$1,100,000	$1,100,000	$5,500,000	$5,500,000	$0	$0	$379,500	$72,930	$118,250	$570,680	$570,680
2	2007	$0	$0	$0	$0	$31,460	$122,100	$379,500	$72,930	$118,250	$724,240	$684,861
3	2008	$0	$0	$0	$0	$31,460	$122,100	$370,670	$70,844	$115,625	$710,699	$635,514
4	2009	$0	$0	$0	$0	$31,460	$122,100	$361,841	$68,758	$113,000	$697,159	$589,509
5	2010	$0	$0	$0	$0	$31,460	$122,100	$353,011	$66,673	$110,375	$683,618	$546,628
6	2011	$0	$0	$0	$0	$31,460	$122,100	$344,181	$64,587	$107,749	$670,077	$506,668
7	2012	$0	$0	$0	$0	$31,460	$122,100	$335,352	$62,501	$105,124	$656,537	$469,436
8	2013	$0	$0	$0	$0	$31,460	$122,100	$326,522	$60,415	$102,499	$642,996	$434,756
9	2014	$0	$0	$0	$0	$31,460	$122,100	$317,692	$58,329	$99,874	$629,455	$402,459
10	2015	$0	$0	$0	$0	$31,460	$122,100	$308,862	$56,244	$97,249	$615,915	$372,389
11	2016	$0	$0	$0	$0	$31,460	$122,100	$300,033	$54,158	$94,624	$602,374	$344,400
12	2017	$0	$0	$0	$0	$31,460	$122,100	$291,203	$52,072	$91,999	$588,834	$318,353
13	2018	$0	$0	$0	$0	$31,460	$122,100	$282,373	$49,986	$89,373	$575,293	$294,120
14	2019	$0	$0	$0	$0	$31,460	$122,100	$273,544	$47,900	$86,748	$561,752	$271,581
15	2020	$0	$0	$0	$0	$31,460	$122,100	$264,714	$45,815	$84,123	$548,212	$250,624
16	2021	$0	$0	$0	$0	$31,460	$122,100	$255,884	$43,729	$81,498	$534,671	$231,143
17	2022	$0	$0	$0	$0	$31,460	$122,100	$247,055	$41,643	$78,873	$521,130	$213,040
18	2023	$0	$0	$0	$0	$31,460	$122,100	$238,225	$39,557	$76,248	$507,590	$196,221
19	2024	$0	$0	$0	$0	$31,460	$122,100	$229,395	$37,471	$73,622	$494,049	$180,602
20	2025	$0	$0	$0	$0	$31,460	$122,100	$220,565	$35,386	$70,997	$480,508	$166,102
21	2026	$0	$0	$0	$0	$31,460	$122,100	$211,736	$33,300	$68,372	$466,968	$152,644
22	2027	$0	$0	$0	$0	$31,460	$122,100	$202,906	$31,214	$65,747	$453,427	$140,159
23	2028	$0	$0	$0	$0	$31,460	$122,100	$194,076	$29,128	$63,122	$439,886	$128,580
24	2029	$0	$0	$0	$0	$31,460	$122,100	$185,247	$27,042	$60,497	$426,346	$117,846
25	2030	$0	$0	$0	$0	$31,460	$122,100	$176,417	$24,957	$57,872	$412,805	$107,899
26	2031	$0	$0	$0	$0	$31,460	$122,100	$167,587	$22,871	$55,246	$399,264	$98,685
27	2032	$0	$0	$0	$0	$31,460	$122,100	$158,758	$20,785	$52,621	$385,724	$90,154
28	2033	$0	$0	$0	$0	$31,460	$122,100	$149,928	$18,699	$49,996	$372,183	$82,260
29	2034	$0	$0	$0	$0	$31,460	$122,100	$141,098	$16,613	$47,371	$358,643	$74,957
30	2035	$0	$0	$0	$0	$31,460	$122,100	$132,268	$14,528	$44,746	$345,102	$68,205
30 YR.TOTAL		$1,100,000		$5,500,000		$912,340	$3,540,900	$7,800,142	$1,341,066	$2,481,689	$16,076,137	$8,740,473
AVERAGE YEARLY COST OVER 30 YEARS						$30,411	$118,030	$260,005	$44,702	$82,723	$535,871	$291,349

Timing of upgrades and intalled cost in 2006 dollars:
Daviess County EHV substation (2006) - $5,500,000
Transmission costs associated with Daviess County EHV substation (2006) - $1,100,000

Inflation: 3% per year
Transmission depreciation: 2.86% calculated from an average of 3.24% for poles and 2.47% for lines from Big Rivers 1997 depreciation study.
Substation depreciation: 2.22% from Big Rivers 1997 depreciation study.
Interest: 5.75% RUS note (cost of debt)
O&M based on 5 year average (2001-2005): 6.63% for transmission and 4.30% for substation (one half of cost).
Present Worth calculated with 5.75% discount rate - RUS note..

345 kV OMU LOOP (2006)

YEAR		TRANS. INVESTMENT 2006 $'s	TRANS. $ INFLATED 3.00%	SUBSTATION INVESTMENT 2006 $'s	SUB $ INFLATED 3.00%	TRANS. DEPR 2.86%	SUBSTATION DEPR 2.22%	TRANS. NET BOOK VALUE	SUBSTATION NET BOOK VALUE	INTEREST 5.75%	TRANS. O&M 6.63%	STATION O&M 4.30%	ANNUAL COST IN NOM. $	PRESENT WORTH (2006)
1	2006	$9,800,000	$9,800,000	$3,900,000	$3,900,000	$0	$0	$9,800,000	$3,900,000	$787,750	$649,740	$167,700	$1,605,190	$1,605,190
2	2007	$0	$0	$0	$0	$280,280	$86,580	$9,800,000	$3,900,000	$787,750	$649,740	$167,700	$1,972,050	$1,864,823
3	2008	$0	$0	$0	$0	$280,280	$86,580	$9,519,720	$3,813,420	$766,656	$631,157	$163,977	$1,928,650	$1,724,617
4	2009	$0	$0	$0	$0	$280,280	$86,580	$9,239,440	$3,726,840	$745,561	$612,575	$160,254	$1,885,250	$1,594,145
5	2010	$0	$0	$0	$0	$280,280	$86,580	$8,959,160	$3,640,260	$724,467	$593,992	$156,531	$1,841,850	$1,472,763
6	2011	$0	$0	$0	$0	$280,280	$86,580	$8,678,880	$3,553,680	$703,372	$575,410	$152,808	$1,798,450	$1,359,867
7	2012	$0	$0	$0	$0	$280,280	$86,580	$8,398,600	$3,467,100	$682,278	$556,827	$149,085	$1,755,050	$1,254,895
8	2013	$0	$0	$0	$0	$280,280	$86,580	$8,118,320	$3,380,520	$661,183	$538,245	$145,362	$1,711,650	$1,157,317
9	2014	$0	$0	$0	$0	$280,280	$86,580	$7,838,040	$3,293,940	$640,089	$519,662	$141,639	$1,668,250	$1,066,641
10	2015	$0	$0	$0	$0	$280,280	$86,580	$7,557,760	$3,207,360	$618,994	$501,079	$137,916	$1,624,850	$982,404
11	2016	$0	$0	$0	$0	$280,280	$86,580	$7,277,480	$3,120,780	$597,900	$482,497	$134,194	$1,581,450	$904,174
12	2017	$0	$0	$0	$0	$280,280	$86,580	$6,997,200	$3,034,200	$576,806	$463,914	$130,471	$1,538,050	$831,546
13	2018	$0	$0	$0	$0	$280,280	$86,580	$6,716,920	$2,947,620	$555,711	$445,332	$126,748	$1,494,651	$764,144
14	2019	$0	$0	$0	$0	$280,280	$86,580	$6,436,640	$2,861,040	$534,617	$426,749	$123,025	$1,451,251	$701,613
15	2020	$0	$0	$0	$0	$280,280	$86,580	$6,156,360	$2,774,460	$513,522	$408,167	$119,302	$1,407,851	$643,623
16	2021	$0	$0	$0	$0	$280,280	$86,580	$5,876,080	$2,687,880	$492,428	$389,584	$115,579	$1,364,451	$589,864
17	2022	$0	$0	$0	$0	$280,280	$86,580	$5,595,800	$2,601,300	$471,333	$371,002	$111,856	$1,321,051	$540,049
18	2023	$0	$0	$0	$0	$280,280	$86,580	$5,315,520	$2,514,720	$450,239	$352,419	$108,133	$1,277,651	$493,908
19	2024	$0	$0	$0	$0	$280,280	$86,580	$5,035,240	$2,428,140	$429,144	$333,836	$104,410	$1,234,251	$451,187
20	2025	$0	$0	$0	$0	$280,280	$86,580	$4,754,960	$2,341,560	$408,050	$315,254	$100,687	$1,190,851	$411,652
21	2026	$0	$0	$0	$0	$280,280	$86,580	$4,474,680	$2,254,980	$386,955	$296,671	$96,964	$1,147,451	$375,082
22	2027	$0	$0	$0	$0	$280,280	$86,580	$4,194,400	$2,168,400	$365,861	$278,089	$93,241	$1,104,051	$341,272
23	2028	$0	$0	$0	$0	$280,280	$86,580	$3,914,120	$2,081,820	$344,767	$259,506	$89,518	$1,060,651	$310,030
24	2029	$0	$0	$0	$0	$280,280	$86,580	$3,633,840	$1,995,240	$323,672	$240,924	$85,795	$1,017,251	$281,177
25	2030	$0	$0	$0	$0	$280,280	$86,580	$3,353,560	$1,908,660	$302,578	$222,341	$82,072	$973,851	$254,544
26	2031	$0	$0	$0	$0	$280,280	$86,580	$3,073,280	$1,822,080	$281,483	$203,758	$78,349	$930,451	$229,977
27	2032	$0	$0	$0	$0	$280,280	$86,580	$2,793,000	$1,735,500	$260,389	$185,176	$74,627	$887,051	$207,328
28	2033	$0	$0	$0	$0	$280,280	$86,580	$2,512,720	$1,648,920	$239,294	$166,593	$70,904	$843,651	$186,463
29	2034	$0	$0	$0	$0	$280,280	$86,580	$2,232,440	$1,562,340	$218,200	$148,011	$67,181	$800,251	$167,254
30	2035	$0	$0	$0	$0	$280,280	$86,580	$1,952,160	$1,475,760	$197,105	$129,428	$63,458	$756,851	$149,582
30 YR.TOTAL		$9,800,000		$3,900,000		$8,128,120	$2,510,820			$15,068,153	$11,947,679	$3,519,486	$41,174,259	$22,917,132
AVERAGE YEARLY COST OVER 30 YEARS						$270,937	$83,694			$502,272	$398,256	$117,316	$1,372,475	$763,904

Timing of upgrades and intalled cost in 2006 dollars:
(2) Elmer Smith 345 kV line terminals (2006) - $3,900,000 (Based on Burns and McDonnell cost for 2 345 kV Wilson Terminals).
8.5 mile double circuit Loop into Elmer Smith (2006) - $9,800,000 (Based on Burns and McDonnell cost for double circuit 161 kV/345 kV).

Inflation: 3% per year
Transmission depreciation: 2.86% calculated from an average of 3.24% for poles and 2.47% for lines from Big Rivers 1997 depreciation study.
Substation depreciation: 2.22% from Big Rivers 1997 depreciation study.
Interest: 5.75% RUS note (cost of debt)
O&M based on 5 year average (2001-2005): 6.63% for transmission and 4.30% for substation.

16 MILE WILSON TO PARADISE (TVA) 161 kV INTERCONNECTION (2006)

YEAR		TRANS. INVESTMENT 2006 $'s	TRANS. $ INFLATED 3.00%	SUBSTATION INVESTMENT 2006 $'s	SUB $ INFLATED 3.00%	TRANS. DEPR 2.86%	SUBSTATION DEPR 2.22%	INTEREST 5.75%	TRANS. O&M 6.63%	STATION O&M 4.30%	ANNUAL COST IN NOM. $	PRESENT WORTH (2006)
1	2006	$6,240,000	$6,240,000	$2,600,000	$2,600,000	$0	$0	$508,300	$413,712	$111,800	$1,033,812	$1,033,812
2	2007	$0	$0	$0	$0	$178,464	$57,720	$508,300	$413,712	$111,800	$1,269,996	$1,200,942
3	2008	$0	$0	$0	$0	$178,464	$57,720	$494,719	$401,880	$109,318	$1,242,101	$1,110,699
4	2009	$0	$0	$0	$0	$178,464	$57,720	$481,139	$390,048	$106,836	$1,214,207	$1,026,719
5	2010	$0	$0	$0	$0	$178,464	$57,720	$467,558	$378,216	$104,354	$1,186,312	$948,587
6	2011	$0	$0	$0	$0	$178,464	$57,720	$453,978	$366,383	$101,872	$1,158,417	$875,917
7	2012	$0	$0	$0	$0	$178,464	$57,720	$440,397	$354,551	$99,390	$1,130,522	$808,345
8	2013	$0	$0	$0	$0	$178,464	$57,720	$426,817	$342,719	$96,908	$1,102,628	$745,532
9	2014	$0	$0	$0	$0	$178,464	$57,720	$413,236	$330,887	$94,426	$1,074,733	$687,160
10	2015	$0	$0	$0	$0	$178,464	$57,720	$399,655	$319,055	$91,944	$1,046,838	$632,931
11	2016	$0	$0	$0	$0	$178,464	$57,720	$386,075	$307,223	$89,462	$1,018,944	$582,568
12	2017	$0	$0	$0	$0	$178,464	$57,720	$372,494	$295,390	$86,980	$991,049	$535,810
13	2018	$0	$0	$0	$0	$178,464	$57,720	$358,914	$283,558	$84,498	$963,154	$492,415
14	2019	$0	$0	$0	$0	$178,464	$57,720	$345,333	$271,726	$82,016	$935,260	$452,155
15	2020	$0	$0	$0	$0	$178,464	$57,720	$331,752	$259,894	$79,535	$907,365	$414,817
16	2021	$0	$0	$0	$0	$178,464	$57,720	$318,172	$248,062	$77,053	$879,470	$380,203
17	2022	$0	$0	$0	$0	$178,464	$57,720	$304,591	$236,230	$74,571	$851,575	$348,127
18	2023	$0	$0	$0	$0	$178,464	$57,720	$291,011	$224,397	$72,089	$823,681	$318,414
19	2024	$0	$0	$0	$0	$178,464	$57,720	$277,430	$212,565	$69,607	$795,786	$290,904
20	2025	$0	$0	$0	$0	$178,464	$57,720	$263,850	$200,733	$67,125	$767,891	$265,444
21	2026	$0	$0	$0	$0	$178,464	$57,720	$250,269	$188,901	$64,643	$739,997	$241,892
22	2027	$0	$0	$0	$0	$178,464	$57,720	$236,688	$177,069	$62,161	$712,102	$220,117
23	2028	$0	$0	$0	$0	$178,464	$57,720	$223,108	$165,237	$59,679	$684,207	$199,995
24	2029	$0	$0	$0	$0	$178,464	$57,720	$209,527	$153,404	$57,197	$656,313	$181,410
25	2030	$0	$0	$0	$0	$178,464	$57,720	$195,947	$141,572	$54,715	$628,418	$164,255
26	2031	$0	$0	$0	$0	$178,464	$57,720	$182,366	$129,740	$52,233	$600,523	$148,430
27	2032	$0	$0	$0	$0	$178,464	$57,720	$168,786	$117,908	$49,751	$572,628	$133,839
28	2033	$0	$0	$0	$0	$178,464	$57,720	$155,205	$106,076	$47,269	$544,734	$120,397
29	2034	$0	$0	$0	$0	$178,464	$57,720	$141,624	$94,244	$44,787	$516,839	$108,020
30	2035	$0	$0	$0	$0	$178,464	$57,720	$128,044	$82,411	$42,305	$488,944	$96,634
30 YR.TOTAL		$6,240,000		$2,600,000		$5,175,456	$1,673,880	$9,735,285	$7,607,502	$2,346,324	$26,538,447	$14,766,490
AVERAGE YEARLY COST OVER 30 YEARS						$172,515	$55,796	$324,509	$253,583	$78,211	$884,615	$492,216

Timing of upgrades and intalled cost in 2006 dollars:
Wilson and Paradise 161 kV line terminals (2006) - $2,600,000 (Based on Burns and McDonnell estimate for a Wilson 161 kV line terminal).
16 mile Wilson to Paradise circuit (2006) - $6,240,000 (Based on Burns and McDonnell estimate for 161 kV construction).

Inflation: 3% per year
Transmission depreciation: 2.86% calculated from an average of 3.24% for poles and 2.47% for lines from Big Rivers 1997 depreciation study.
Substation depreciation: 2.22% from Big Rivers 1997 depreciation study.
Interest: 5.75% RUS note (cost of debt)
O&M based on 5 year average (2001-2005): 6.63% for transmission and 4.30% for substation.

APPENDIX E: TRANSMISSION PLANNING CRITERIA AND GUIDELINES

Big Rivers
Electric Corporation

Transmission Planning Criteria and Guidelines
September 13, 2006

A Touchstone Energy Cooperative

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I. GENERAL SYSTEM PLANNING REQUIREMENTS

Big Rivers' transmission system consists of the physical equipment necessary to transmit power from its generating plants and interconnection points to all substations from which customers of its three member distribution cooperatives are served. Transmission planning embodies making investment decisions required to maintain this system so that it can reliably meet the power needs of the customers served. Justifications used in any such decisions are based on technical and economic evaluations of options that may be implemented to meet these needs.

The technical studies performed by the system planning section require the use of several software packages. The software package PSLF (Positive Sequence Load Flow) is a comprehensive set of transmission system planning programs supported by the General Electric Company. The programs include AC and DC power flow, power flow equivalent, auto-contingency, stability, and others.

A software package for short-circuit calculations and relay coordination is also used. This package is known as CAPE (The Computer-Aided Power Engineering System) and is supported by Electrocon International Inc.

The above-described software programs are used to aid in the preparation of seasonal assessments, short-term construction work plans and long-range engineering plans as defined and required by RUS. Power flow studies for specific operating conditions are also performed to support system operations. Special power flow studies and transfer capability studies are also performed as needed.

II. POWER FLOW STUDIES

The most widely used software program for transmission system planning is the power flow program. In order to get consistent and meaningful results from power flow studies, specific criteria and procedures have been established and are followed. Succeeding sections of the document describe the contingency criteria, voltage criteria, line and transformer loading criteria, and modeling procedures established and used by Big Rivers for transmission system planning.

1. Contingency Criteria

Big Rivers follows two RUS recommended criteria for analyzing the adequacy of its transmission system. The first criterion defines single contingency outages to be used in all system planning studies. This criteria serves as the basis for planning and justifying system improvements. The second criterion outlines double contingency outages that can be analyzed to determine the extent of problems encountered on the system under extreme outage or emergency situations. In most double contingency cases, system improvements would not be considered justifiable. However, the type and severity of the system problems encountered is useful information in planning those system improvements that are justifiable.

Single Contingency Criteria:

1. Outage of two generation units (any combination).
2. Outage of one generation unit and one transmission line.
3. Outage of one generating unit and one transformer.
4. Outage of one transmission line.

Double Contingency Criteria:

1. Outage of two transmission lines on the same right-of-way.
2. Outage of transmission lines due to outage of one bus.
3. Outage of three generation units.

In addition to the above-described criteria, Big Rivers also analyzes its transmission system to ensuring compliance with NERC Planning Standards.

2. Voltage Criteria

As indicated in the following table, Big Rivers has adopted a voltage criteria for its 161 kV and 69 kV transmission system. This criteria defines acceptable minimum and maximum voltage levels for the high-side buses at all delivery points. The criteria include a range of acceptable voltages for normal system conditions (all facilities in service) and during single contingency conditions. A more detailed description of the voltage criteria is included as appendix A.

Transmission System Conditions	69 kV Bus Voltage		161kV Bus Voltage	
	Minimum	Maximum	Minimum	Maximum
Range A: Normal System Operations	95.0%	105.0%	95.0%	105.0%
Range B: Single Contingency Conditions	91.7%	105.8%	92.0%	105.0%

3. Line and Transformer Loading Criteria

Big Rivers' transmission lines are rated according to limits determined by the most restrictive of either the conductor thermal ratings, the NESC minimum line to ground clearances, or the terminal equipment ratings. Big Rivers' transformer ratings are established according to their thermal design ratings as specified by the manufacturer. For normal and single contingency situations, all lines are to be loaded at or below their ratings and all transformers are to be loaded at or below their maximum 65°C ratings. Additional rating details can be found in the appendicies.

4. Substation Equipment Rating Criteria

Big Rivers' substation equipment ratings are based on manufacturer recommendations. Big Rivers does not derate high voltage air switches, line traps, or power circuit breakers based on weather conditions or previous loading conditions. Shunt capacitors are designed for a minimum of 1.05 p.u. voltage. Jumpers connecting these substation components to other elements of the transmission system are sized with current carrying capacity greater than the component itself. Additional rating details can be found in the appendicies.

5. Modeling Procedures

In order to perform a power flow study, a model of the electrical system is required. The power flow model requires line and transformer impedances, transformer tap settings, generation levels, load levels (MW and MVAR), scheduled voltages, line and transformer ratings, and interchange schedules for Big Rivers' facilities as well as for other utilities.

To start the model development process, an MMWG power flow case for a desired year is obtained. This model includes information for neighboring utilities within SERC as well as other reliability areas. Neighboring utilities can be contacted directly in order to obtain more detailed system information. After the MMWG case is obtained, the Big Rivers model and any desired neighboring utility representations are removed and more detailed models are merged into the case.

After all detailed representations are merged into the MMWG case, fine-tuning of the case begins. The first step is to make sure Big Rivers' interchange is correct. The modeled interchange should typically reflect firm contract sales for the desired time period. Transactions that are consistent with firm transmission reservations that are confirmed on the OASIS may also be modeled as part of Big Rivers' scheduled interchange. Close attention must be paid to HMP&L's allocation from Station 2 generation and HMP&L's loads (in the MMWG case, the HMP&L take should be modeled as Big Rivers load. HMP&L load should be modeled in a separate HMP&L area in the detailed case). After the interchange is modeled, the loads in Big Rivers' area are reviewed and revised. The loads should be properly distributed and should match the forecast numbers found in the latest available Big Rivers load forecast for the desired year.

Regression techniques or averages based on historical data can be used to distribute the rural load. The large industrial loads modeled in the power flow case should match the values given in the Big Rivers load forecast. Each distribution cooperative should be consulted during this load distribution process. Additional details regarding this process are included in Appendix B. In most cases, the generation at Reid 1 and at the Reid CT is modeled at 0. All transmission or generation construction scheduled to be completed before the time period to be studied is added into the model. A final check of line and transformer impedances and ratings is performed prior to starting the desired power flow studies.

III. SHORT CIRCUIT STUDIES

System planning utilizes short circuit study results to evaluate the adequacy of the short time current or interrupting ratings of existing equipment, to determine the ratings of new equipment to be purchased, and to provide short circuit source data to its member cooperatives, their industrial customers, or for Big Rivers' own protection coordination studies. System planning currently performs these short circuit studies. Short circuit studies are performed using the CAPE software package.

In order to perform these short circuit studies, a database model including the positive and zero sequence impedances of each line, transformer, and generator is prepared for Big Rivers' system. Equivalent system impedances for each of Big Rivers' interconnections is also determined and modeled. Short circuit studies are then run to determine the magnitude of single phase to ground and three phase faults at each station or bus in Big Rivers' system. These fault levels are compared to the existing power circuit breaker ratings to determine if any equipment ratings are exceeded. If equipment ratings are exceeded, then upgrades in equipment are recommended.

IV. STABILITY STUDIES

Another concern of the system planning section is system stability. Stability refers to the ability of a generator to remain in synchronism with all other generators after a disturbance or fault. Stability analysis is broken down into two components, transient and dynamic stability. Transient stability studies look at an extremely short time period just before and just after a disturbance or fault. Dynamic stability studies encompass a somewhat longer time period.

Transient stability is typically of more concern than dynamic stability. Transient stability is affected by the strength of the transmission system, the characteristics of different generators, and the speed in which a disturbance is disconnected. Transient stability studies are used to help determine critical fault clearing times necessary to maintain system stability. These initial fault clearing times would be the basis for relay application and equipment application decisions on both existing and new transmission facilities.

Stability studies are typically performed in conjunction with either major construction projects such as the addition of generation and possibly transmission interconnection facilities or heavy power transfer conditions over the existing system facilities. Consultants have been utilized to perform the majority of these studies in the past. However, the stability program included in PSLF has also been used for critical clearing time studies. The criteria followed during stability studies follows:

1. Under normal system peak load conditions with full generation output, all generating units must remain stable with a three phase-to ground fault at the most critical location.

2. With one transmission element out-of-service, all generating units must remain stable with a subsequent single phase-to-ground fault.

3. Under normal system peak load conditions with full generation output, all generating units must remain stable with a single phase-to-ground fault at the most critical location followed by a breaker failure.

4. All circuit breakers should be capable of interrupting the maximum fault current duty imposed on the circuit breaker.

V. CONSTRUCTION WORK PLANS

RUS requires that borrowers maintain an up-to-date short-range construction work plan (CWP). The CWP consists of a series of system studies, which covers a period of 2 to 3 years in the future and identifies required transmission facility improvements. The CWP should be consistent with the long-range engineering plan. The CWP studies use the system load estimates found in the borrower's approved load forecast. A CWP, according to RUS, shall normally include studies of power flows, voltage regulation, and stability characteristics to demonstrate system performance and needs. These requirements, as well as additional requirements, are described in the Federal Register in 7 CFR Part 1710.

A CWP, as prepared by Big Rivers, covers a three year period beyond the year in which the study is being performed. For example, a CWP prepared in the summer of 1995 would cover the time frame from 1996 to 1998. New CWPs are typically prepared during the last year covered by an existing CWP.

Power flow studies make up the majority of a CWP as prepared by Big Rivers. A power flow database is prepared as previously described. Load levels that are consistent with the most current load forecast are modeled. Typically, the interchange is modeled according to firm contract sales and purchases. However, transactions that are consistent with firm transmission reservations that are confirmed on the OASIS may also be modeled as part of Big Rivers' scheduled interchange. Single contingency outages of each line of Big Rivers' system (excluding radial lines) are studied. Single contingencies, which yield unacceptable system results, are identified. Alternate systems switching arrangements or changes in transformer tap settings are evaluated as the first solution option. If operational changes will not correct the problem, then system improvement alternatives are defined, modeled, and studied to determine their merits in correcting the system problem. The system improvements that prove to be successful solutions for the system problem are then evaluated based on economics, reliability, practicality, possible system benefits, and consistency with long range engineering plans to determine their inclusion in the CWP recommendation. Power flow studies are typically run for summer and winter peak conditions. Power flow studies with extreme conditions (peak load forecast with extreme weather) are also performed and may be used to evaluate construction alternatives.

Maximum transfer capability studies may be included as a part of the CWP. A maximum transfer capability study typically includes four scenarios modeled to evaluate potential sales. Maximum power transfer studies from Big Rivers to TVA and MISO would be evaluated. The intent of these studies runs is to identify any system problems that may occur because of off-system sales.

Short circuit studies to evaluate the adequacy of system equipment ratings are also performed and their results analyzed. Stability studies accompany any study in which additional generation is being recommended or evaluated.

VI. LONG-RANGE ENGINEERING PLANS

RUS also requires that borrowers maintain up-to-date long-range engineering plans. These long-range engineering plans are prepared in a manner that is very similar to the process of preparing a CWP. A long-range engineering plan is prepared immediately following each CWP. This allows the CWP to be reviewed in light of long-range plans. Reviewing and revising a long-range engineering plan is acceptable in place of preparing an entirely new study if system changes and load forecast changes have been minimal. Engineering judgement is used to decide if simply reviewing and revising the study is appropriate.

As with a CWP, the long-range engineering plan is predominantly driven by the results of system power flow studies. The power flow studies are again prepared with an MMWG database. This database represents all systems ten years in the future. A detailed representation of Big Rivers, and any desired neighbor, is merged into the MMWG database. The load level modeled for Big Rivers are to be consistent with the approved load forecast for the desired year. The power flow cases are modeled with summer peak and off-peak loads. The modeled interchange reflects what Big Rivers' management believes is most probable for the study period. This interchange level may be equivalent to firm contract sales and purchases or may include transactions that are consistent with firm transmission reservations that are confirmed on the OASIS. Single contingency outages of each Big Rivers' line (excluding radial lines) are studied. These single contingency studies identify cases that yield unacceptable voltages or line loading conditions. Studies are then run to evaluate possible solutions for the problems. Operational changes such as switching or transformer tap changes are the first solution options studied. If operational changes proved to be unsuccessful, then various system improvement options are studied. All system improvements that are found to be successful solutions for the system problems are then evaluated based on economics, reliability, practicality, and other system benefits to determine the best solution. Additional system studies are run to evaluate the cumulative effects of multiple system improvements. The end result is a system configuration that would allow Big Rivers to serve its members' long-range loads in a reliable and cost-effective manner.

In addition to the ten-year study, a fifteen or twenty year study may be performed. A procedure, similar to the ten-year study procedure, would be followed with a fifteen or twenty year power flow database. Any final conclusions would be made using the results from both the ten-year study and the fifteen or twenty year study.

Maximum power transfer capability studies may also be prepared as part of a long-range engineering plan. These studies will help to identify any problems that may occur in the long run as a result of off-system sales. Possible solutions to correct the deficiencies are identified and evaluated following normal power flow study procedures.

Short circuit studies are also performed as previously described. These studies help identify long-term problems associated with increasing fault duties. Stability studies accompany any study in which additional generation is being recommended or evaluated.

It should be noted that not every system addition or upgrade identified or proposed in the long-range engineering is implemented. As Big Rivers' system actually grows, it may become obvious that the problems identified in the long-range study may not develop or that problems may develop in other areas. The actual system development is continually reviewed and monitored to determine when a new long-range engineering plan is necessary. The long-range plan, when reviewed with the CWP, helps to identify any proposed short run solutions that may just be "band-aid" solutions for a major long-range problem. In some of these cases, investing in a facility that may only be a temporary solution may not be advisable. Instead, other alternatives may be more economical when the long-term system needs are considered.

VII. MISCELLANEOUS PLANNING STUDIES

The power flow and short circuit programs are used for many types of studies. In addition to the CWPs, operational studies and various other special studies are performed. It is common to investigate possible load additions or potential off-system sales with the power flow program. The actual process and format of these studies will vary according to need. Some of these studies may require that only a small portion of the system be evaluated. All of these studies, however, are consistent with the criteria outlined in this report.

On an annual basis, studies are prepared to evaluate all annual firm transmission requests (new or renewals). Other studies are performed to support the calculation of the ATC values that are posted to the OASIS. Details concerning these studies are included in a separate document.

Seasonal system assessments are also prepared on an annual basis. These seasonal assessments include (at a minimum) summer peak studies, winter peak studies, stress cases (heavy transfers), and long-range studies. Single, double, and extreme contingencies should be studied with the results compared against NERC Planning Standard 1A requirements. Stability studies should also be reviewed as necessary.

Big Rivers Electric Corporation

Appendices to the Transmission Planning Criteria and Guidelines September 13, 2006

APPENDIX A:

Voltage Level Criteria Guideline

APPENDIX A: VOLTAGE LEVEL CRITERIA GUIDELINE

In 1989, Big Rivers adopted a voltage criteria for use as a guideline in planning for the design and operation of its transmission system. This criteria was based on service voltage requirements defined by the Kentucky Public Service Commission (PSC) and the Rural Utilities Service (RUS). This criteria was defined as the acceptable voltage level at the unregulated distribution and/or industrial substation low-voltage buses (served from Big Rivers' 69 kV transmission system). This criteria, summarized below, includes a Range A criteria which is applied during normal system operations (all transmission elements in service) and a Range B criteria that is applied during single contingencies.

Transmission System Conditions	Minimum Bus Voltage	Maximum Bus Voltage
Range A: Normal System Operations	95.0%	105.0%
Range B: Single Contingency Conditions	91.7%	105.8%

A second criteria, which applies to Big Rivers' 161 kV transmission system, has also been adopted. The development of this criteria also involved a review of PSC and RUS voltage requirements. This criteria was based on maintaining acceptable voltage levels on the low-side unregulated bus at all 161 kV delivery points. The Range A and Range B criteria apply to the same system conditions as defined for the 69 kV system. These criteria limits are defined below:

Transmission System Conditions	Minimum Bus Voltage	Maximum Bus Voltage
Range A: Normal System Operations	95.0%	105.0%
Range B: Single Contingency Conditions	90.0%	105.0%

Both criteria, as previously defined, were applied to the low-side unregulated buses. For transmission planning purposes, a voltage criteria that applies to the high side buses was developed. When reflecting the voltage criteria to the high side bus, transformer regulation (voltage drop across the transformer) and the boost supplied by the no load tap changers was considered. Low-side voltage regulators or load tap changers were not considered.

When developing the low voltage criteria limit for the 69 kV delivery points, it was assumed that the transformer would be set on their mid-tap. In most cases, the mid-tap is 67 kV. With a 67 kV nominal tap, the transformer regulation is offset. In the few instances that the transformer mid-tap is 69 kV, it is assumed that the fixed tap could be changed to a boost position (which would offset the transformer regulation). When calculating the transformer regulation, it was assumed that the transformer was two-thirds loaded with a 90% power factor.

When developing the low voltage criteria limit for the 161 kV delivery points, it was assumed that the transformer would be set with one fixed tap of boost. It was also assumed that the transformers would be two-thirds loaded (with the corresponding transformer regulation). If a customer taking service from the 161 kV system has special needs which a 90% to 105% voltage criteria fail to meet, an LTC may be used to maintain acceptable voltage levels under both normal and single-contingency conditions.

To protect against damage due to high voltages during off-peak times or instances when a transformer may be unloaded (little or no transformer regulation would be expected), the high voltage limits were not changed when the criteria was reflected to the high-side bus.

The high-side voltage ranges included below were found to be necessary to maintain the low-side voltage criteria. However, the operator should not wait until voltages fall outside of the accepted range to take action. System operators should take all available actions to maintain voltages between .95 P.U. and 1.05 P.U. This includes, but is not limited to, switching capacitors and reactors, changing the voltage schedules at the generator buses, and utilizing load tap changers.

Transmission System Conditions	69kV Bus Voltage		161 kV Bus Voltage	
	Minimum	Maximum	Minimum	Maximum
Range A: Normal System Operations	95.0%	105.0%	95.0%	105.0%
Range B: Single Contingency Conditions	91.7%	105.8%	92.0%	105.0%

APPENDIX B:

Load Distribution and Modeling

LOAD DISTRIBUTION AND MODELING

A key part of the database development is load modeling. Big Rivers prepares a load forecast on an annual basis. This load forecast is built from individual member cooperative load forecast forecasts. The loads modeled in the power flow database should be consistent with the Big Rivers coincident peak load forecast with the loads distributed among all of the member cooperative substations.

Regression techniques have been used to help distribute the loads on an individual substation basis. Historical substation data is collected for each delivery point. The data series for each substation is regressed on time using a simple linear curve equation. In addition, the load at each substation is forecasted by applying the system average growth rate (from the cooperative forecast) to an average of the two most recent years coincident peak data. These two forecast values, along with input from each distribution cooperative and engineering judgment, are used to create a forecasted load for each delivery point. These forecast are uniformly ratioed to match the overall Big Rivers coincident peak forecast. This method allows the historical trends to be reflected in the load distribution while consistency with the overall load forecast is maintained.

Industrial customers with dedicated delivery points are forecasted by the individual industries. As part of the load forecast preparation, all large industrial customers are contacted and asked to supply a forecast for their energy needs and expected peak demand. These forecasts are used to model these individual customers.

HMP&L personnel should provide HMP&L load. This load should be modeled in a separate area in the detailed power flow cases. However, in the MMWG models, the HMP&L take (HMP&L load supplied from Station 2) should be modeled as load at Henderson County, Reid 161 kV, and Reid 69 kV.

Power factors for each load are also based on historical data. The actual power factors at each delivery point during the most recent coincident peak for both summer and winter seasons are used. Since this historical power factor information is generally based on low-side meter data, adjustments are necessary when modeling loads on the high-side of the distribution transformers. This adjustment is typically accomplished by reducing the power factors by 98% to 99%. The percent adjustment is calculated on a seasonal basis for each distribution cooperative by modeling a distribution transformer loaded at 50% with a low-side power factor equal to the system average power factor during the most recent coincident peak. Loads metered on the high-side need no adjustment (this includes: Kimberly-Clark, Lodestar, P&M, Patriot Coal, Hopkins County Coal, ALCAN, and Century).

Appendix C:

Substation Equipment Rating Criteria

Interoffice Memo

To: David Crockett

From: Bob Warren

CC:

Date: 4-19-99

Subject: 87 Facility Ratings: High Voltage Air Switches

Big Rivers Electric purchases, operates and maintains transmission voltage (100 kV and above) High Voltage Air Switches in accordance with ANSI C37.32 *HV Air Switches – Preferred Ratings, Specifications and Application Guide*. Table 1 of C37.32 lists *Preferred Ratings for Outdoor Air Switches*. Big Rivers does not derate High Voltage Air Switches based on weather conditions or previous loading conditions. Jumpers connecting switches to other elements of the transmission facility are sized with current carrying capacity greater than the switch itself.

Big Rivers
Electric Corporation

Memorandum

To: David Crockett

From: Bob Warren

CC:

Date: 8-16-04

Subject: 87 Facility Ratings: Shunt Capacitors

Big Rivers Electric purchases, operates and maintains transmission voltage (100 kV and above) Shunt Capacitors in accordance with NEMA CP1 - Shunt Capacitors, and ANSI/IEEE C37.99 – Guide for Protection of Shunt Capacitor Banks, and IEEE 1036 Guide for the Application of Shunt Power Capacitors. These capacitor banks are composed of capacitor can groups in series and connected in a grounded wye configuration. Since substation bus voltages run higher than 1.0 p.u., banks are designed for a minimum of 1.05 p.u. Jumpers connecting capacitor banks to other elements of the transmission system are sized with current carrying capacity greater than the capacitor bank itself.

Interoffice Memo

To: David Crockett

From: Bob Warren

CC:

Date: 4-19-99

Subject: 87 Facility Ratings: Line Traps

Big Rivers Electric purchases, operates and maintains transmission voltage (100 kV and above) Line Traps in accordance with ANSI C93.3 – *Requirements for Power-Line Carrier Line Traps*. Table 5 of C93.3 lists *Current Ratings*. Big Rivers does not derate Line Traps based on weather conditions or previous loading conditions. Jumpers connecting Line Traps to other elements of the transmission facility are sized with current carrying capacity greater than the Line Trap itself.

Big Rivers
Electric Corporation

Memorandum

To: David Crockett

From: Bob Warren

CC:

Date: 11-12-04

Subject: Facility Ratings - Power Transformers

Big Rivers Electric plans and operates power transformers on its system whose voltage ratings fall within the bulk transmission level (100 kV and above high side). Big Rivers has established that the normal and emergency rating for power transformers shall be the highest nameplate rating with all cooling equipment operating. For most of the Big Rivers transformers, this is the maximum FOA or FA (OFAF or ONAF) 65 degree Celsius nameplate rating with all cooling equipment operating. In the absence of any or all stages of cooling equipment, the rating is the maximum nameplate rating associated with that level of cooling. For the six 345/161 kV power transformers the rating is 420 MVA (a significant increase above the nameplate value as determined by the manufacturer, General Electric Company). However, if these units are operated in a step-up mode (direction of flow from 161 kV to 345 kV system), either the high side voltage must be limited to 345 kV (1.0 per unit) or the unit rating reverts back to the 336 MVA nameplate value.

Interoffice Memo

To: David Crockett

From: Bob Warren

CC:

Date: 2-24-00

Subject: 87 Facility Ratings: High Voltage Bus

Big Rivers Electric purchases, operates and maintains transmission voltage (100 kV and above) High Voltage Bus in accordance with ANSI / IEEE Standard 605 – 1987 *Guide for Design of Substation Rigid-Bus Structures.* Table B3 of Standard 605 Appendix B lists *Bus Conductor Ampacity - Aluminum Tubular Bus –Schedule 40 AC Ampacity (53% Conductivity).* Big Rivers utilizes this table assuming a normal oxidized surface with emissivity of 0.50, with sun, in still but unconfined air, with a 30 degree C temperature rise over 40 degrees C ambient.

Interoffice Memo

To: David Crockett

From: Bob Warren

CC:

Date: 1-27-00

Subject: 87 Facility Ratings: Transformers

Big Rivers Electric purchases, operates and maintains transmission voltage (100 kV and above) Transformers in accordance with ANSI / IEEE C57.12.00 – 1987 *General Requirements for Liquid Immersed Power Transformers* and ANSI / IEEE C57.92 – 1981 *Loading Mineral Oil Immersed Power Transformers.* Big Rivers utilizes Figure 3 of C57.92 *Maximum Loss of Life – 65 Degree C Rise Transformers* and will allow no more than one percent loss of life for one occurrence.

Interoffice Memo

To: David Crockett

From: Bob Warren

CC:

Date: 4-19-99

Subject: 87 Facility Ratings: Power Circuit Breakers

Big Rivers Electric purchases, operates and maintains transmission voltage (100 kV and above) Power Circuit Breakers in accordance with ANSI C37.06 *AC HV Circuit Breakers – Preferred Ratings and Related Required Capabilities*. Table 3 of C37.06 lists *Preferred Ratings for Outdoor Circuit Breakers 121 kV and Above*. Big Rivers does not derate PCBs based on weather conditions or previous loading conditions. PCBs on the Big Rivers transmission system are equipped with Bushing Current Transformers (BCTs). These BCTs are usually Multi-ratio and sometimes tapped at less than the full continuous current rating of the PCB. In these situations the PCB is derated to the Multi-Ratio BCT tap value. The Thermal Rating Factor of the BCT is used where applicable. Jumpers connecting PCBs to other elements of the transmission facility are sized with current carrying capacity greater than the PCB itself.

Appendix D:

Transmission Line Rating Information

Memo

To: David Crockett

From: Chris Bradley

CC:

Date: 1/24/00

Re: NERC Standard for Transmission Line Rating (II.C.S1.M1)

Big Rivers Electric Corporation transmission facility ratings are based on the most limiting element included in any circuit (switches, breakers, buses, traps, protection systems, transformers, CTs, transmission lines, etc.) The calculations of transmission line ratings are consistent with IEEE Standard 738-1993 "IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors". The following assumptions are utilized in the calculations:
1). Minimum ground clearances (as defined by NESC) will be maintained during operations at the conductor's maximum operating temperature (typically 212° F).
2). Summer Normal and Summer Emergency ratings are calculated with 2 foot per second wind speed, full sun, and an ambient temperature of 100° F.
3). Winter Normal and Winter Emergency ratings are calculated with 2 foot per second wind speed, full sun, and an ambient temperature of 32° F.
4). In addition to the above ratings, temperature dependent ratings are used by system operations (actual temperatures are used in place of the assumed temperature when calculating the ratings).

Interoffice Memo

To: System Operations Personnel

From: David Crockett

CC:

Date: 2/20/06

Subject: Transmission Line Switches

This memorandum will serve to document the criteria applied in the planning, design, construction, and operation of line switches on Big Rivers' transmission system. The focus here is on the 69 kV system serving all of the rural and many of the dedicated (customer) delivery point substations of our three member cooperatives. The following functional objectives and standards define the 69 kV transmission line switching practices currently in effect.

<u>For loop or dual feed line sections:</u>

1. Line sectionalizing switches shall be employed at both ends of every line section.
2. Full load interrupting capability shall exist at a minimum on one end of every line section.
3. Load interrupting capability shall exist on the other end line sectionalizing switch of sufficient rating to safely de-energize the line (i.e. break the line charging current).
4. Remote control operational equipment shall be added to full load interrupting switches to solve service reliability problems and typically shall be applied at three-way junction points to provide alternate power supply switching arrangements for a number of distribution stations.

<u>For radial line sections:</u>

1. Line sectionalizing switches shall be applied for tap lines greater than 4.0 miles in length or where continuous service is essential to other stations supplied off the radial line section being tapped.
2. Line sectionalizing switches shall have sufficient load interrupting capability to safely de-energize the line (i.e. minimum capability equal to or greater than line charging current).

Interoffice Memo

To: David Crockett

From: Bob Warren

CC:

Date: 10-25-02 Revised

Subject: 87 - Transmission Facility Ratings

Big Rivers Electric operates transmission voltage (100 kV and above) facilities according to the attached Loadability Table. The table identifies various limiting elements on each transmission line terminal. The lines are sorted in rows according to voltage with 345 kV lines listed first.

Equipment and conductor ratings exclusive of Current Transformer Ratio limitations are listed in the first set of columns. These columns indicate that the limiting component is usually the conductor. However both 345 kV lines are limited by 1600 A line disconnect switches. Bryan Rd, Meade County and Newman 161 kV radial lines are limited by their transformation capacity. While the Henderson County 138 kV line and the Hardinsburg 138 kV Cloverport line are limited by a line trap.

Limiting Current Transformer Ratios are identified in the next set of columns. CTRs are only listed if they are set lower than the conductor would allow.

The next four columns check all components of the transmission facility and report the minimum rating. Listed are the Summer and Winter MVA and Amp ratings for each transmission line.

Appendix E:

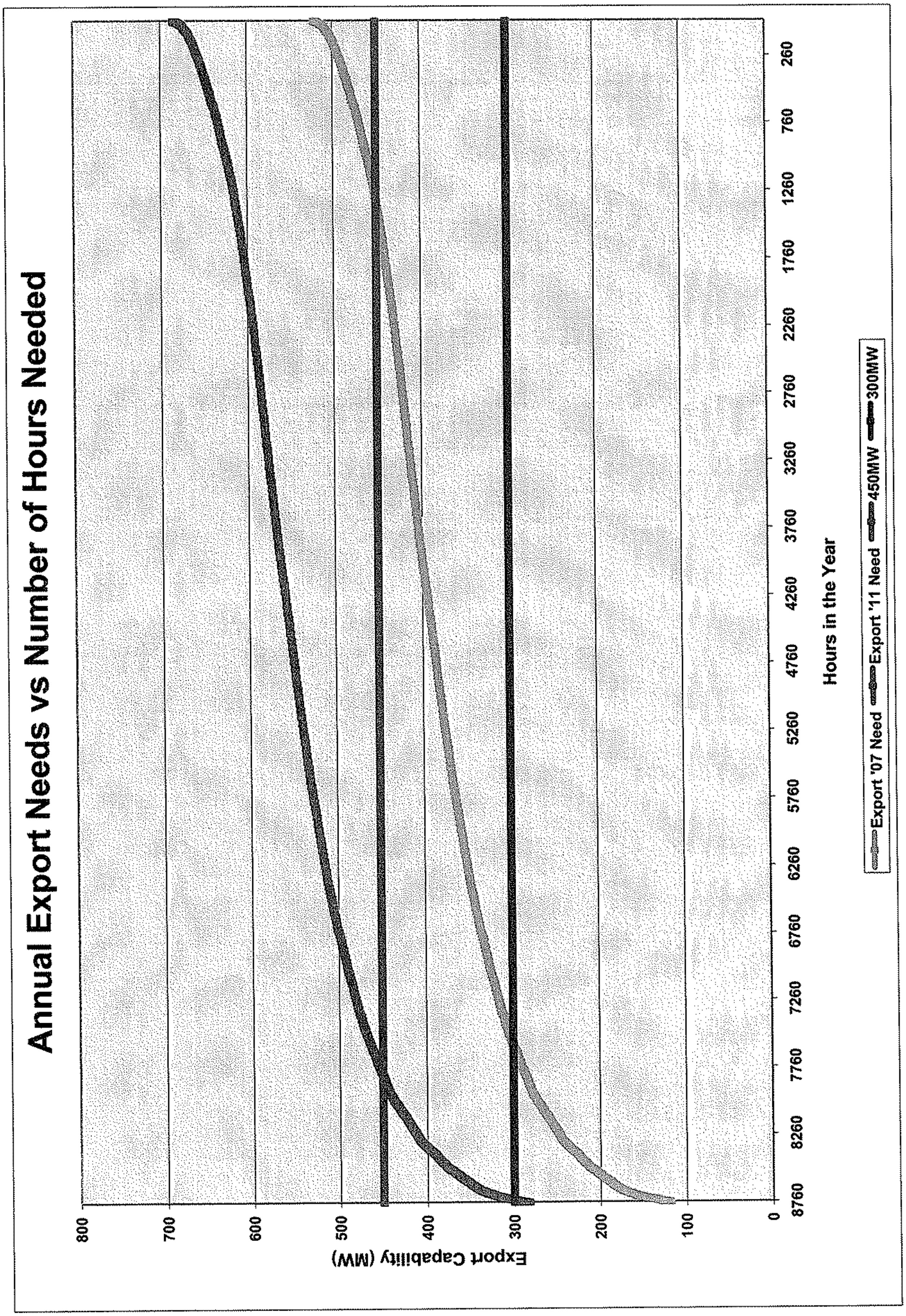
Transformer Information

Appendix F:

Shunt Information

Appendix G:

Loadability Tables



Annual Export Needs vs Number of Hours Needed
Export Capability (MW)
800
700
600
500
400
300
200
100
0
8760
8260
7760
7260
6760
6260
5760
5260
4760
4260
3760
3260
2760
2260
1760
1260
760
260
Hours in the Year
Export '07 Need
Export '11 Need
450MW
300MW

Exhibit E

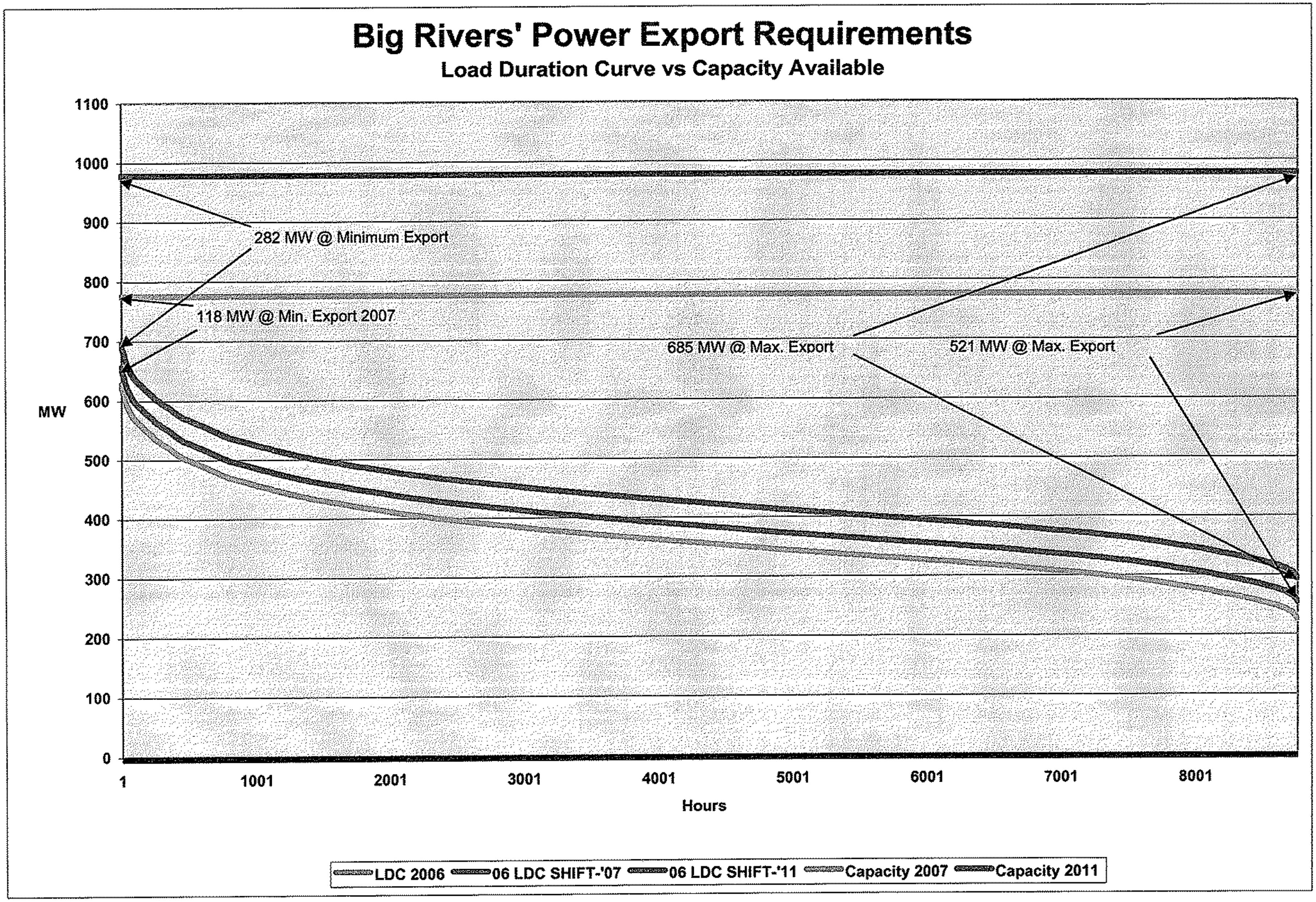

Big Rivers' Power Export Requirements
Load Duration Curve vs Capacity Available
MW
1100
1000
900
800
700
600
500
400
300
200
100
0
282 MW @ Minimum Export
118 MW @ Min. Export 2007
685 MW @ Max. Export
521 MW @ Max. Export
1
1001
2001
3001
4001
5001
6001
7001
8001
Hours
LDC 2006
06 LDC SHIFT-'07
06 LDC SHIFT-'11
Capacity 2007
Capacity 2011

Exhibit F