MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

ORIGINAL

January 13, 2012

RECEIVED

JAN 17 2012

PUBLIC SERVICE COMMISSION

Executive Secretary
North Dakota Public Service Commission
State Capitol Building
Bismarck, ND 58505-0480

Re: Late Filed Exhibits
Case Nos. PU-11-395 & PU-11-396

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., herewith submits Late Filed Exhibits MDU-113, MDU-114 and RSH-12 as requested at the technical hearing on January 10, 2012:

The original and seven (7) copies of this letter of transmittal and Late Filed Exhibits have been filed with the Commission and provided to the parties noted below.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Tamie A. Aberle
Regulatory Affairs Manager

Cc: Dan Kuntz
Mark Gruman
Illona Jeffcoat-Sacco

Enclosure

48 PU-11-396 Filed 01/17/2012 Pages: 159
Late filed exhibits MDU-113, MDU-114, and RSH-12 (most of RSH-12 is in electronic form only)
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.

61 PU-11-395 Filed 01/17/2012 Pages: 159
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Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.

Montana Dakota Utilities Co.
Case Nos. PU-11-395 and PU-11-396
Late Filed Exhibits

Exhibit MDU-113

Provide a List of Montana-Dakota's qualitative considerations associated with the proposed 88 MW combustion turbine to be located near the Heskett Station.

The following considerations support the Company's application to pursue the installation of a 88 MW Combustion Turbine at the Heskett site to meet a portion of the Company's demand requirements beginning in 2015. The list includes both quantitative and qualitative considerations in addition to the Company's least cost modeling and sensitivities included in such modeling; although Montana-Dakota has not attempted to determine specific quantitative values for some of the considerations that might be considered quantitative considerations.

- Increased system reliability
- Job creation (The project is expected to create 2 fulltime permanent operator positions and construction jobs.)
- Additional state income tax revenues
- Additional property tax revenue
- Additional state sales tax revenue both from construction materials and ongoing O&M material purchases
- Synergies with Heskett Station
- Usage of available transmission
- Long-term benefits of an owned resource
- Age of existing generation fleet
- Avoidance of Western Area Power Administration Network Integration Service charges
- Avoidance of a MISO Transmission Service Agreement and charges for off-system resources
- Reduced dependence on 3rd parties for generation capacity and transmission service
- Effect of MISO participant withdrawal
- Brownfield site versus greenfield site
- Location near largest customer load pocket in the Bismarck-Mandan area
- Uncertainty of MISO resource adequacy construct
- Expected generation unit retirements within MISO
- Current market pricing and availability of construction labor and generating equipment
- No current opportunities to partner with others on larger plant

Montana Dakota Utilities Co.
Case Nos. PU-11-395 and PU-11-396
Late Filed Exhibits

Exhibit MDU-114

Provide a copy of the 2009 Capability Study referenced in the testimony of Darcy J. Neigum

Please see Attachment A entitled "Montana-Dakota Utilities Transmission Capability" which is an internal report based on a 2009 load study in the Bismarck-Mandan area to determine the amount of loading serving capability that the Company has without support from the WAPA Integrated System (IS). The WAPA Transmission Service Agreement currently provides 169 MW of load-serving capability from the WAPA Transmission System in the Bismarck-Mandan Area. The results of this capability study show that upon expiration of the WAPA Transmission Service Agreement in 2015, in a limiting single contingency situation, the Company would only be able to service 142 MW of Bismarck-Mandan load assuming Heskett Generation at 100 MW and 59 MW of Bismarck-Mandan load would be served assuming no Heskett Generation is available.

All loads above 142 MW would require Network Transmission Service from the WAPA IS at the published tariff rate for firm point-to-point transmission. For 2010, the posted WAPA IS firm point-to-point transmission rate was $2.95 per kW-month as shown on Attachment B.

Attachment C entitled "WAPA Transmission Exhibit H Analysis" provides a summary comparison of the Company's system peak loads on July 23, 2007 for hour ending 1800 (Montana-Dakota's integrated system coincident peak) as compared to Exhibit H from the WAPA Transmission Service Agreement that dictates the amount of load Montana-Dakota is allowed to currently serve under the WAPA Transmission Service Agreement. As shown, Montana-Dakota is currently able to serve 169 MW (Exhibit H) plus 142 MW (capability study results) in the Bismarck-Mandan area without support from the WAPA Integrated System. Montana-Dakota's peak load on July 23, 2007 (all-time summer peak of 525 MW at the time of the 2009 study) was 226.8 MW for hour ending 1800 in the Bismarck-Mandan area.

Exhibit MDU-114
Attachment A

Montana-Dakota Utilities Company
Transmission Capability

By Shawn Heilman

Introduction

The purpose of this study is to determine the capability of the MDU transmission system to serve its load when separated from the Integrated System (IS) transmission. The area evaluated in this study is Bismarck-Mandan-Beulah. The study area transmission system was evaluated under system intact and N-1 conditions.

Analysis

The MRO 2008 series 2010 summer peak (MRO2008series-2010S-final.sav) case was used for the analysis.

The area was evaluated by switching off the WAPA and BEPC loads in the area and separating the area from IS transmission by opening the following lines:

- Bismarck-East Bismarck 115 kV line
- Heskett-Ward 230 kV line
- Heskett-Dickinson 230kV line
- Beulah-Garrison 115 kV line
- Beulah-Halliday 115 kV line

The capacity of the MDU transmission system for the Bismarck-Mandan-Beulah area was determined by scaling the study area load by 5 MW increments for System Intact and N-1 scenarios until a steady-state violation occurs.

Table 1 Criteria for Steady-State analysis

	System Intact Conditions		N-1 Contingency Conditions	
Transmission Facilities	Continuous Rating (Rate A)		Emergency Rating (Rate B)	
Bus Voltage	Max 1.05 pu	Min 0.95 pu	Max 1.10 pu	Min 0.90 pu

Results

The Bismarck-Mandan-Beulah area was studied with the Heskett generation offline and online at 100 MW. A load and a load plus losses (shown as Ties below) number was calculated to determine the load serving capabilities of the MDU transmission. Appendix A & B have PSS/E Slider diagrams for each scenario studied.

Table 2.1 – Results Heskett Generation Offline

Outage	Area Load (MW)	Area Ties (MW)	Limiting Facility
System Intact	133	135	Heskett 230/115 xfmr
Heskett 230/115 xfmr	68	75	Voltage
Center-Heskett 230 line	59	70	Beulah-Heskett 115 kV line
Heskett-Wishek 230 line	153	155	Heskett 230/115 xfmr
Beulah-Heskett 115 line	129	130	Heskett 230/115 xfmr
Coyote-Beulah 115 line	124	125	Heskett 230/115 xfmr
Heskett-Bismarck NW 115 line	156	160	Heskett 230/115 xfmr
Heskett-NW Mandan 115 line	160	165	Heskett 230/115 xfmr

Table 2.2 – Results Heskett Generation Online

Outage	Area Load (MW)	Area Ties (MW)	Limiting Facility
System Intact	222	225	Heskett 230/115 xfmr
Heskett 230/115 xfmr	142	145	Voltage
Center-Heskett 230 line	164	175	Beulah-Heskett 115 kV line
Heskett-Wishek 230 line	246	250	Heskett 230/115 xfmr
Beulah-Heskett 115 line	223	225	Heskett 230/115 xfmr
Coyote-Beulah 115 line	213	215	Heskett 230/115 xfmr
Heskett-Bismarck NW 115 line	172	175	Heskett-NW Mandan 115 kV line
Heskett-NW Mandan 115 line	172	175	Heskett-Bismarck NW 115 kV line
Heskett Generation	162	165	Heskett 230/115 xfmr

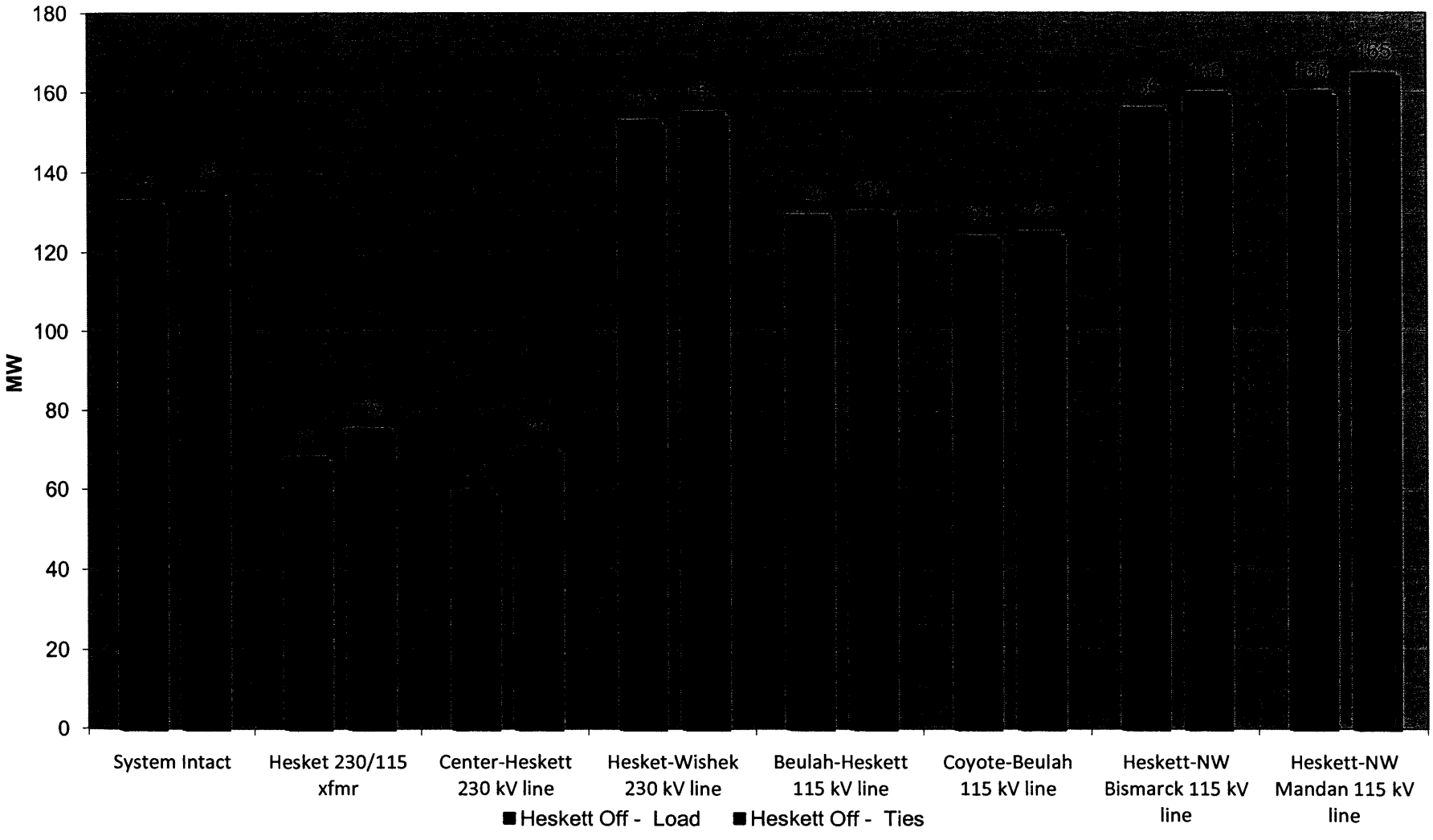
Conclusion

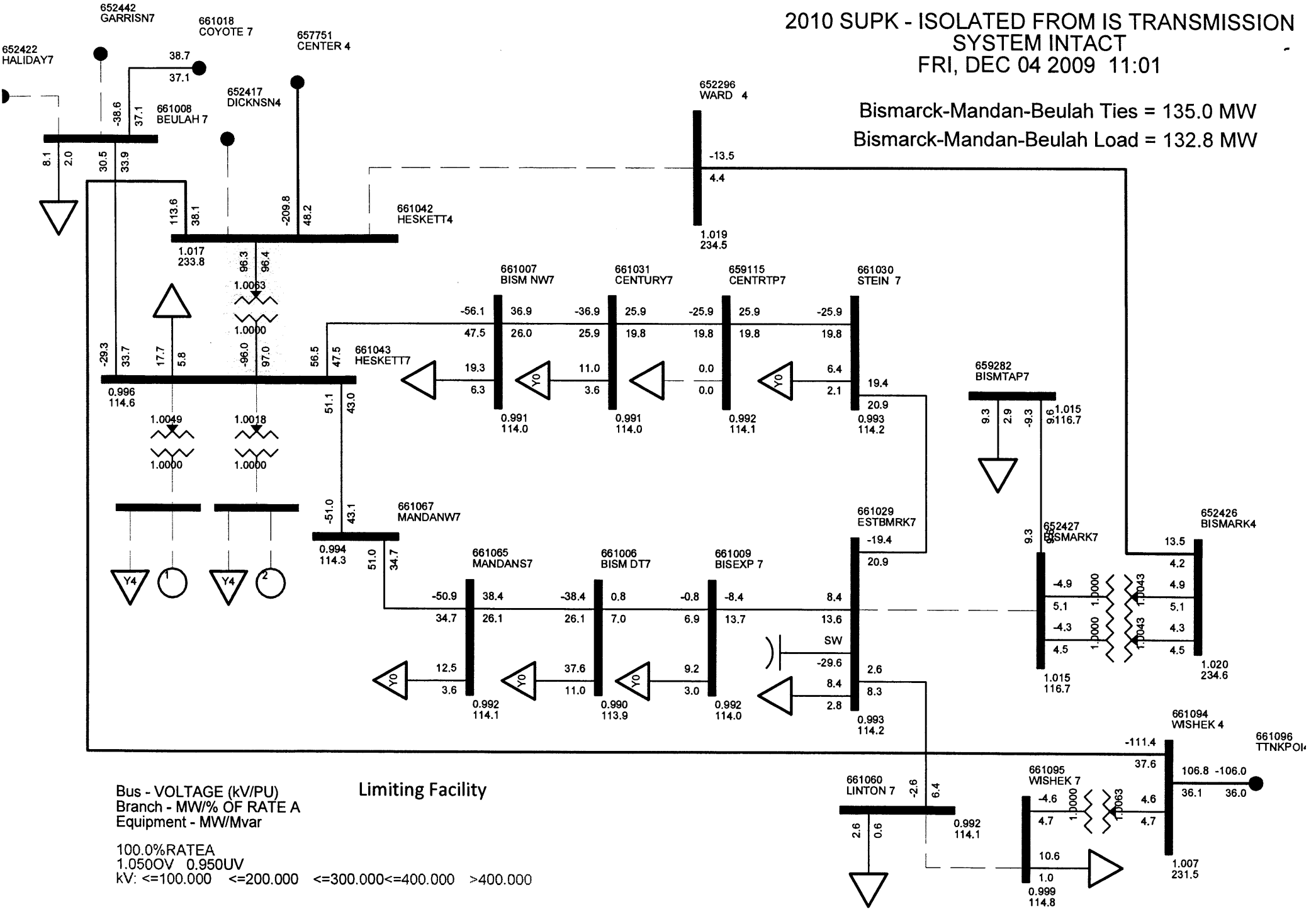
The load serving capabilities of the MDU Bismarck-Mandan-Beulah transmission facilities with Heskett generation online is 145 MW and with Heskett generation offline is 70 MW.

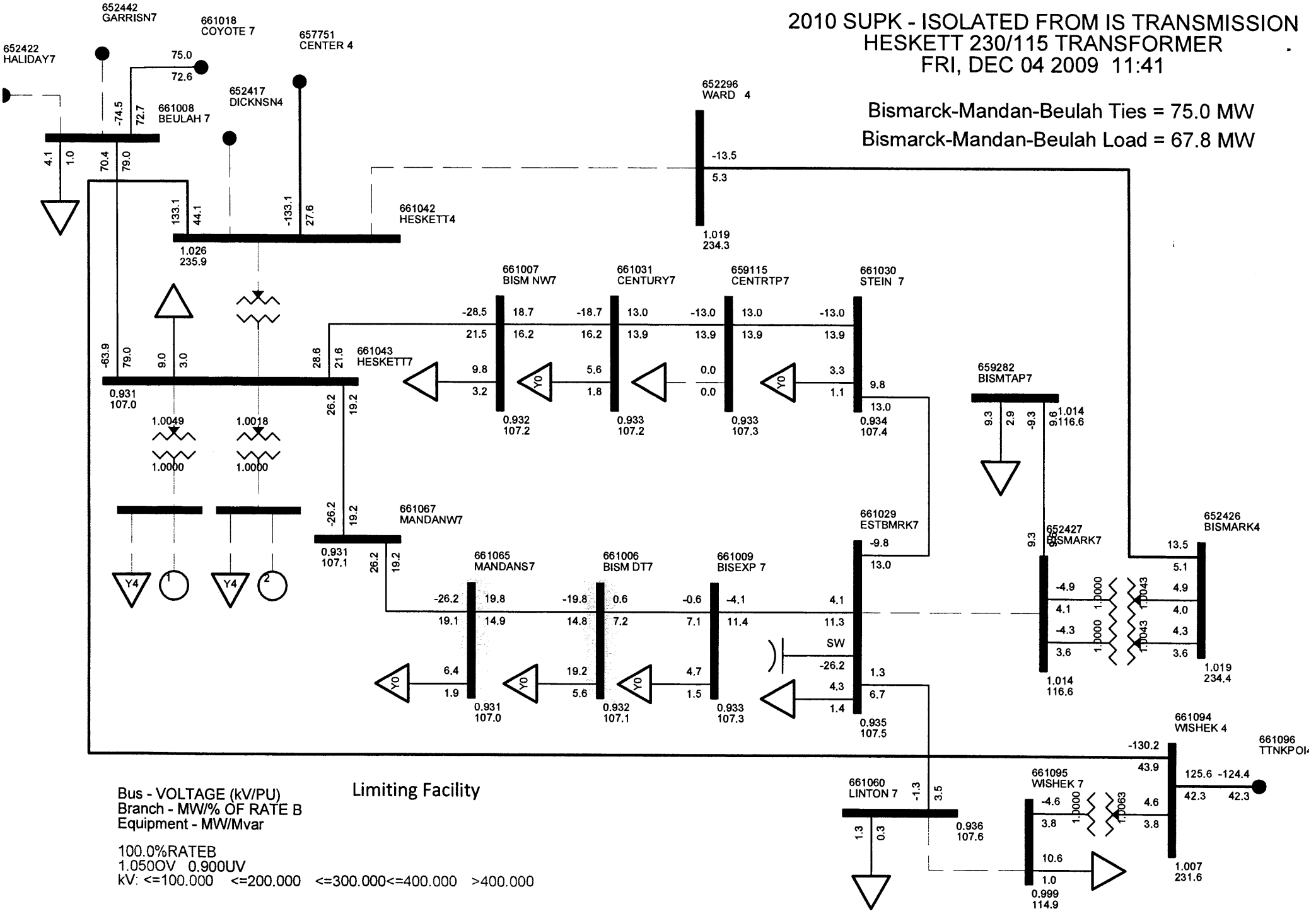
Appendix A

Heskett Generation Offline

MDU Load Serving Capabilities - No Heskett Gen.
Bismarck-Mandan-Beulah




2010 SUPK - ISOLATED FROM IS TRANSMISSION SYSTEM INTACT
FRI, DEC 04 2009 11:01
Bismarck-Mandan-Beulah Ties = 135.0 MW
Bismarck-Mandan-Beulah Load = 132.8 MW
652442 GARRISN7
661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
661008 BEULAH 7
652417 DICKNSN4
652296 WARD 4
661042 HESKETT4
661007 BISM NW7
661031 CENTURY7
659115 CENTRTP7
661030 STEIN 7
661043 HESKETT7
659282 BISMTAP7
661067 MANDANW7
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661029 ESTBMRK7
652427 BISMARK7
652426 BISMARK4
661094 WISHEK 4
661096 TTNKPOI
661060 LINTON 7
661095 WISHEK 7
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE A
Equipment - MW/Mvar
Limiting Facility
100.0%RATEA
1.050OV 0.950UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000


2010 SUPK - ISOLATED FROM IS TRANSMISSION
HESKETT 230/115 TRANSFORMER
FRI, DEC 04 2009 11:41
Bismarck-Mandan-Beulah Ties = 75.0 MW
Bismarck-Mandan-Beulah Load = 67.8 MW
652442 GARRISN7
661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
661008 BEULAH 7
652417 DICKNSN4
652296 WARD 4
661042 HESKETT4
661007 BISM NW7
661031 CENTURY7
659115 CENTRTP7
661030 STEIN 7
661043 HESKETT7
659282 BISMTAP7
661067 MANDANW7
661029 ESTBMRK7
652427 BISMARK7
652426 BISMARK4
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661094 WISHEK 4
661096 TTNKPOI
661095 WISHEK 7
661060 LINTON 7
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE B
Equipment - MW/Mvar
Limiting Facility
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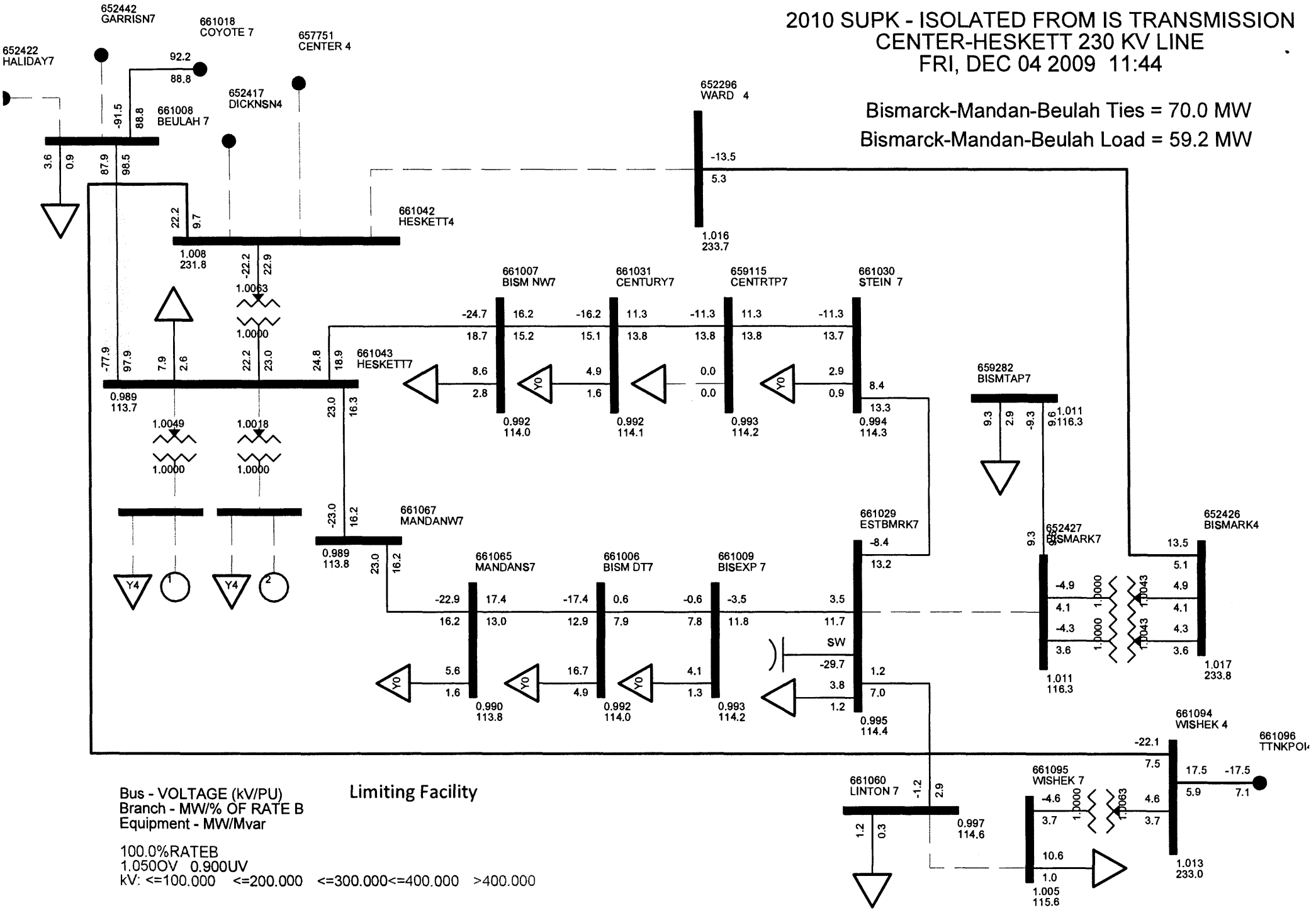
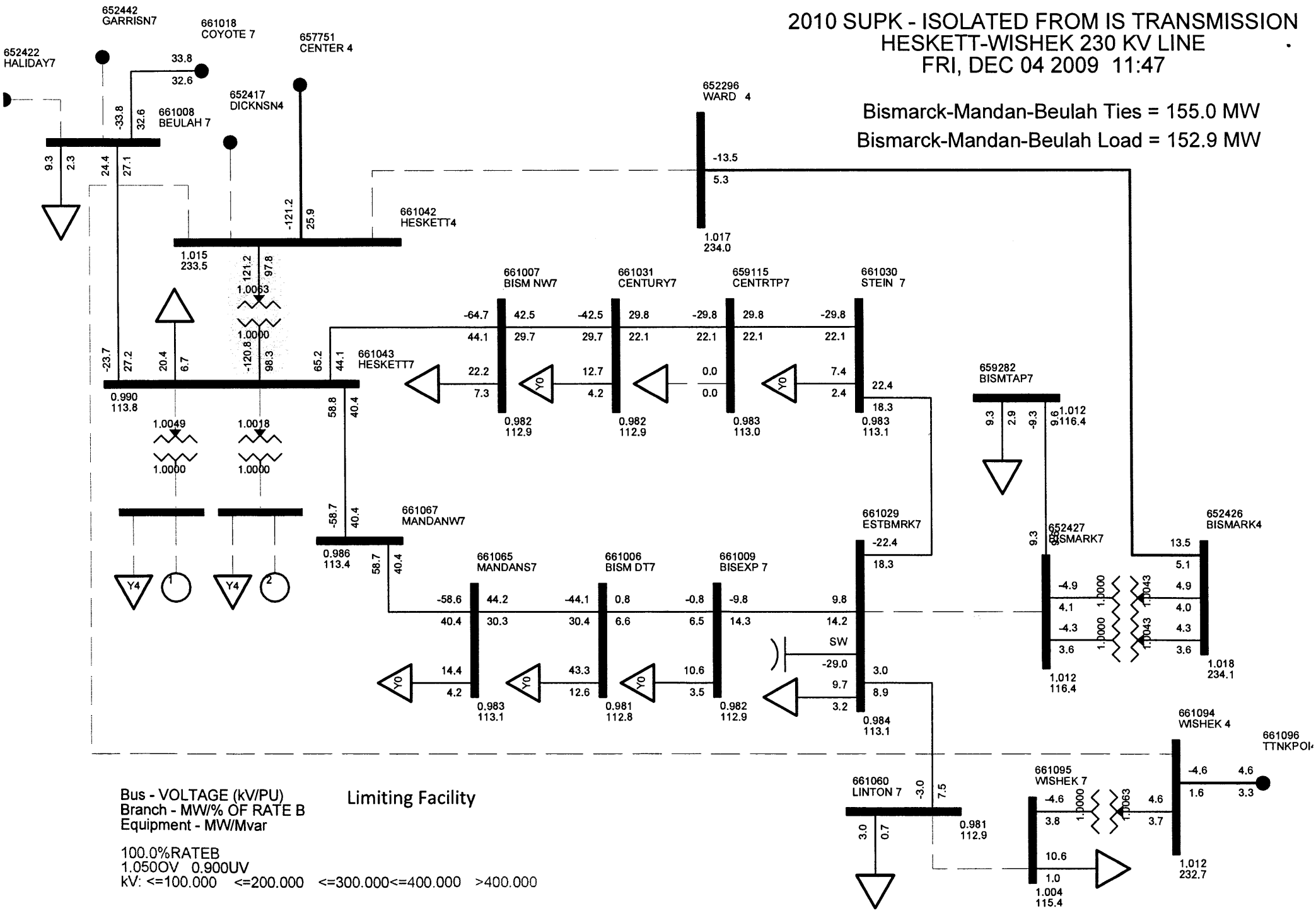
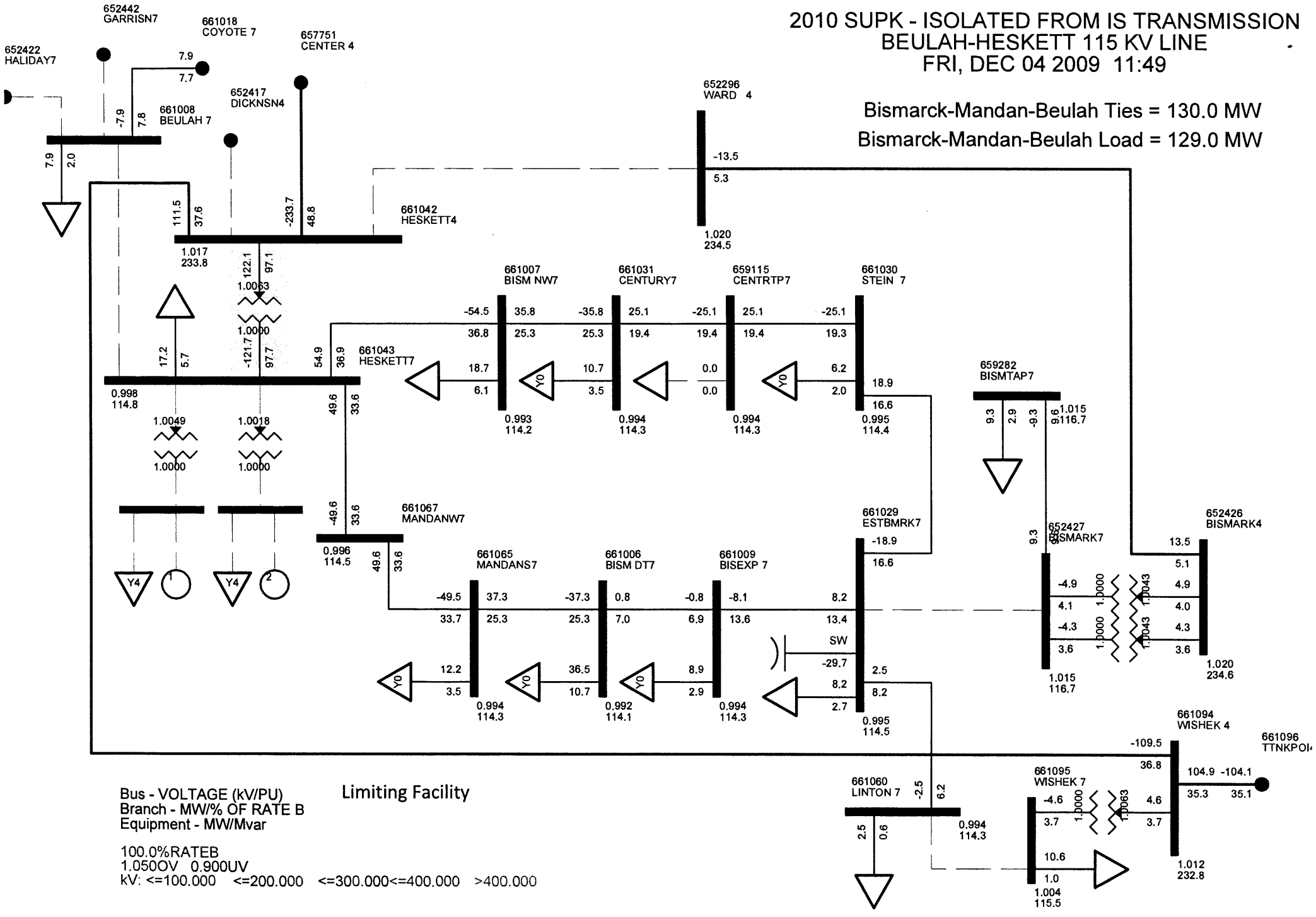
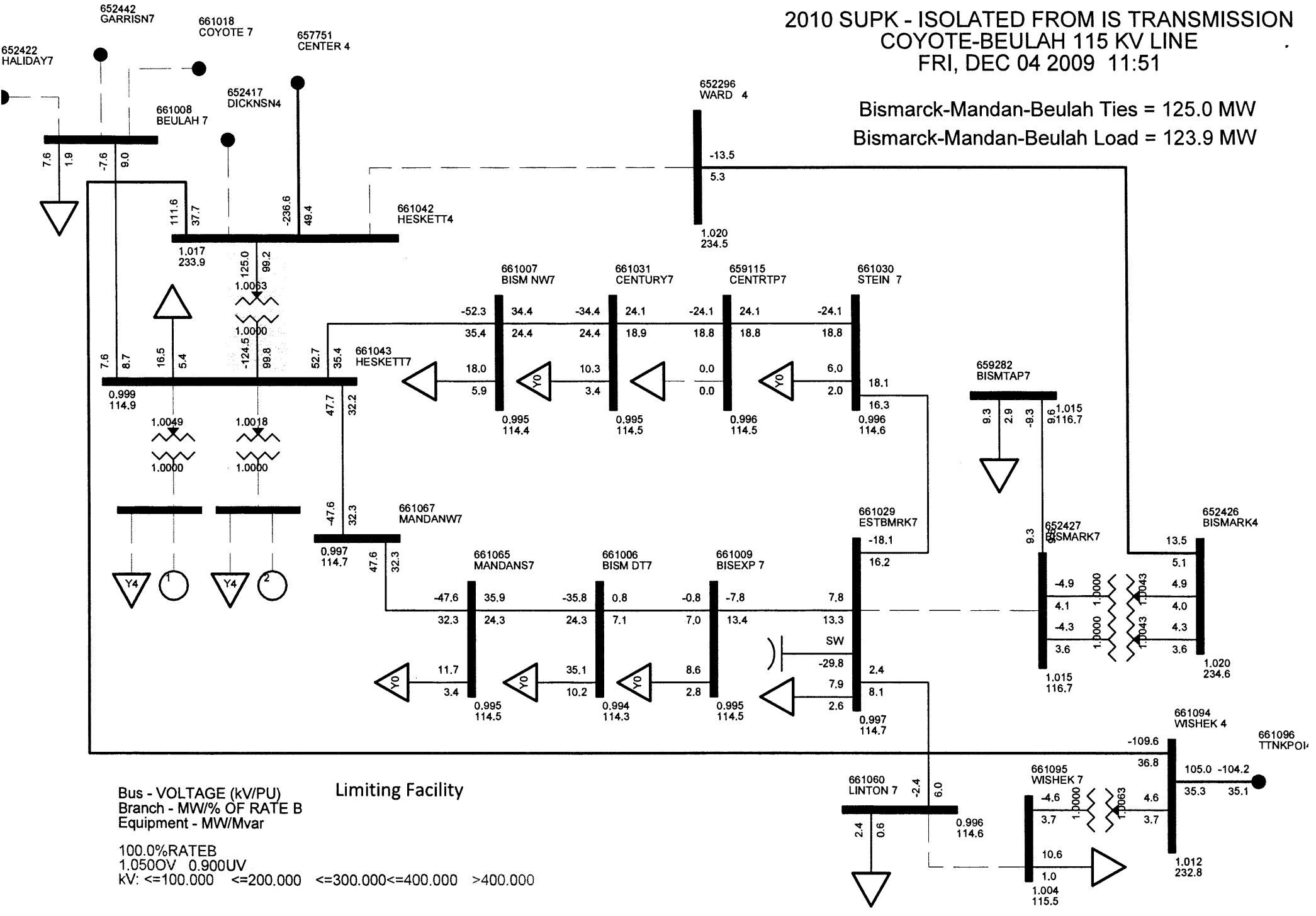
1.050OV 0.900UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000


2010 SUPK - ISOLATED FROM IS TRANSMISSION
CENTER-HESKETT 230 KV LINE
FRI, DEC 04 2009 11:44
Bismarck-Mandan-Beulah Ties = 70.0 MW
Bismarck-Mandan-Beulah Load = 59.2 MW
652442 GARRISN7
661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
661008 BEULAH 7
652417 DICKNSN4
652296 WARD 4
661042 HESKETT4
661043 HESKETT7
661007 BISM NW7
661031 CENTURY7
659115 CENTRTP7
661030 STEIN 7
659282 BISMTAP7
652427 BISMARK7
652426 BISMARK4
661067 MANDANW7
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661029 ESTBMRK7
661094 WISHEK 4
661096 TTNKPOI
661060 LINTON 7
661095 WISHEK 7
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE B
Equipment - MW/Mvar
Limiting Facility
100.0%RATEB
1.050OV 0.900UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000


2010 SUPK - ISOLATED FROM IS TRANSMISSION
HESKETT-WISHEK 230 KV LINE
FRI, DEC 04 2009 11:47
Bismarck-Mandan-Beulah Ties = 155.0 MW
Bismarck-Mandan-Beulah Load = 152.9 MW
652442 GARRISN7
661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
661008 BEULAH 7
652417 DICKNSN4
652296 WARD 4
661042 HESKETT4
661043 HESKETT7
661007 BISM NW7
661031 CENTURY7
659115 CENTRTP7
661030 STEIN 7
659282 BISMTAP7
661067 MANDANW7
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661029 ESTBMRK7
652427 BISMARK7
652426 BISMARK4
661060 LINTON 7
661095 WISHEK 7
661094 WISHEK 4
661096 TTNKPOI
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE B
Equipment - MW/Mvar
Limiting Facility
100.0%RATEB
1.050OV 0.900UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000


2010 SUPK - ISOLATED FROM IS TRANSMISSION
BEULAH-HESKETT 115 KV LINE
FRI, DEC 04 2009 11:49
Bismarck-Mandan-Beulah Ties = 130.0 MW
Bismarck-Mandan-Beulah Load = 129.0 MW
652442 GARRISN7
661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
661008 BEULAH 7
652417 DICKNSN4
652296 WARD 4
661042 HESKETT4
661007 BISM NW7
661031 CENTURY7
659115 CENTRTP7
661030 STEIN 7
661043 HESKETT7
659282 BISMTAP7
661067 MANDANW7
661029 ESTBMRK7
652427 BISMARK7
652426 BISMARK4
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661094 WISHEK 4
661096 TTNKPOI
661060 LINTON 7
661095 WISHEK 7
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE B
Equipment - MW/Mvar
Limiting Facility
100.0%RATEB
1.050OV 0.900UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000


2010 SUPK - ISOLATED FROM IS TRANSMISSION
COYOTE-BEULAH 115 KV LINE
FRI, DEC 04 2009 11:51
Bismarck-Mandan-Beulah Ties = 125.0 MW
Bismarck-Mandan-Beulah Load = 123.9 MW
652442 GARRISN7
661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
652417 DICKNSN4
661008 BEULAH 7
652296 WARD 4
661042 HESKETT4
661007 BISM NW7
661031 CENTURY7
659115 CENTRTP7
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659282 BISMTAP7
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661029 ESTBMRK7
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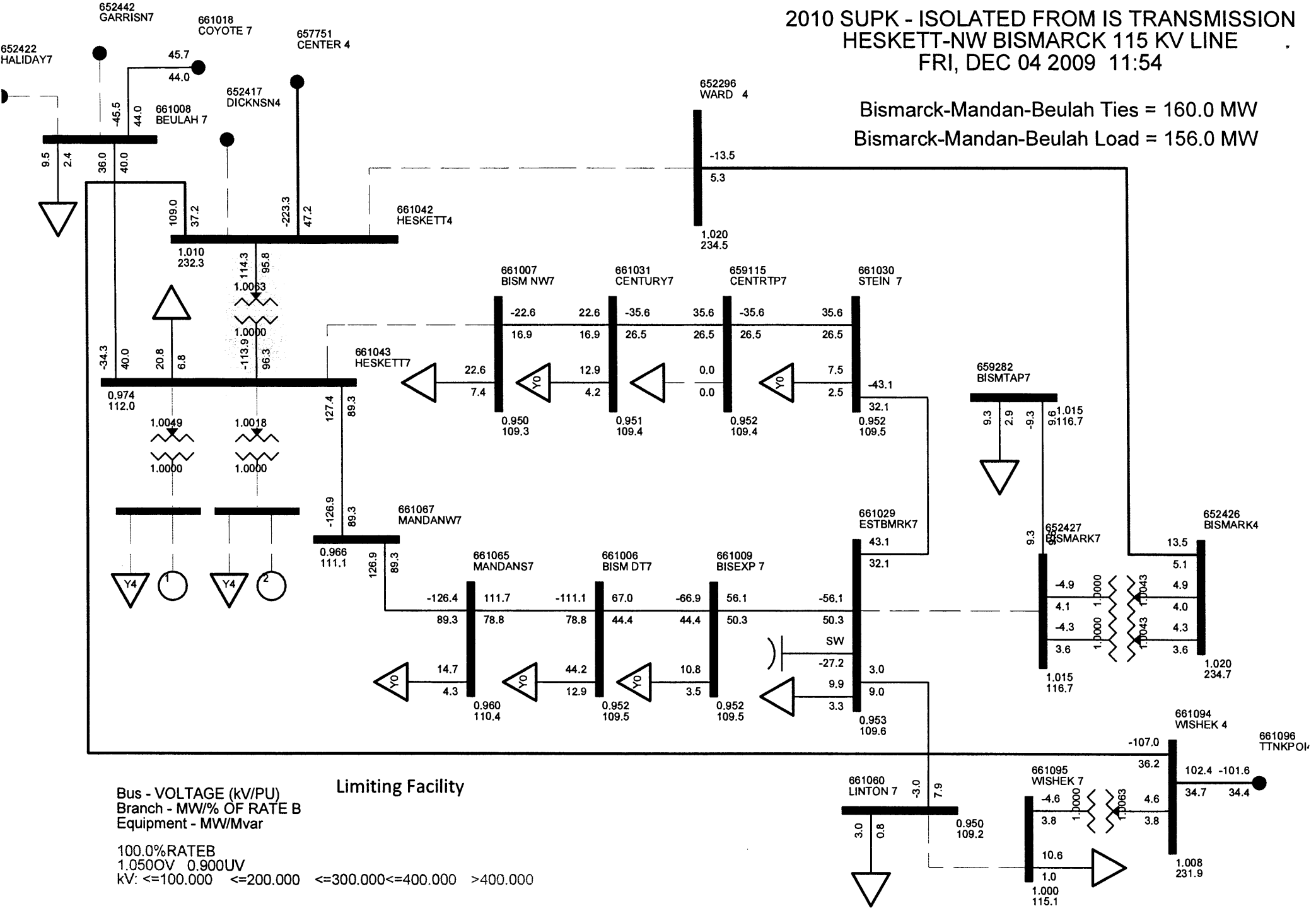
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661094 WISHEK 4
661096 TTNKPOI
661060 LINTON 7
661095 WISHEK 7
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE B
Equipment - MW/Mvar
Limiting Facility
100.0%RATEB
1.050OV 0.900UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000


2010 SUPK - ISOLATED FROM IS TRANSMISSION
HESKETT-NW BISMARCK 115 KV LINE
FRI, DEC 04 2009 11:54
Bismarck-Mandan-Beulah Ties = 160.0 MW
Bismarck-Mandan-Beulah Load = 156.0 MW
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661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
652417 DICKNSN4
661008 BEULAH 7
652296 WARD 4
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659115 CENTRTP7
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661067 MANDANW7
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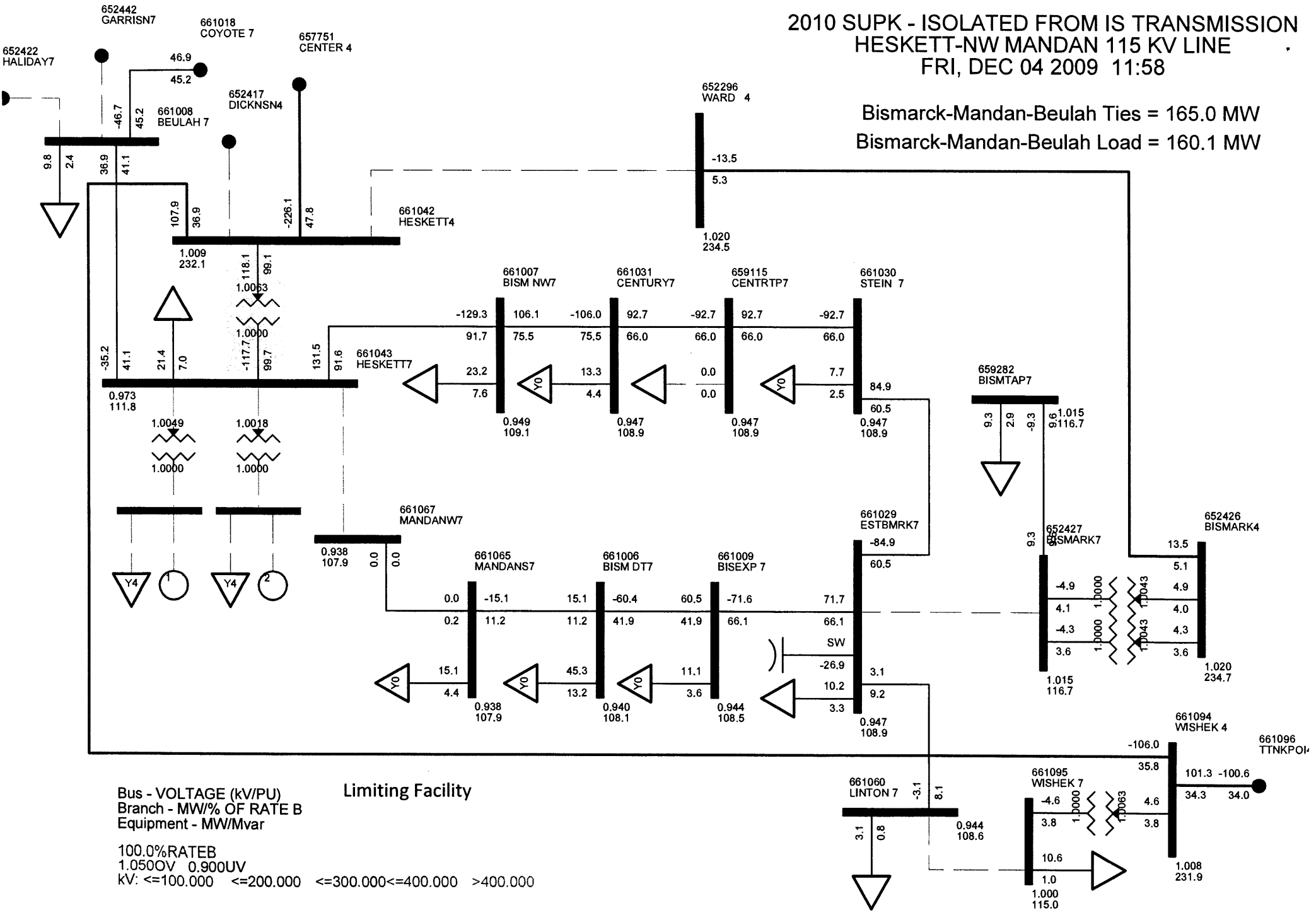
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661094 WISHEK 4
661096 TTNKPOI
661060 LINTON 7
661095 WISHEK 7
Limiting Facility
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE B
Equipment - MW/Mvar
100.0%RATEB
1.050OV 0.900UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000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HESKETT-NW MANDAN 115 KV LINE
FRI, DEC 04 2009 11:58
Bismarck-Mandan-Beulah Ties = 165.0 MW
Bismarck-Mandan-Beulah Load = 160.1 MW
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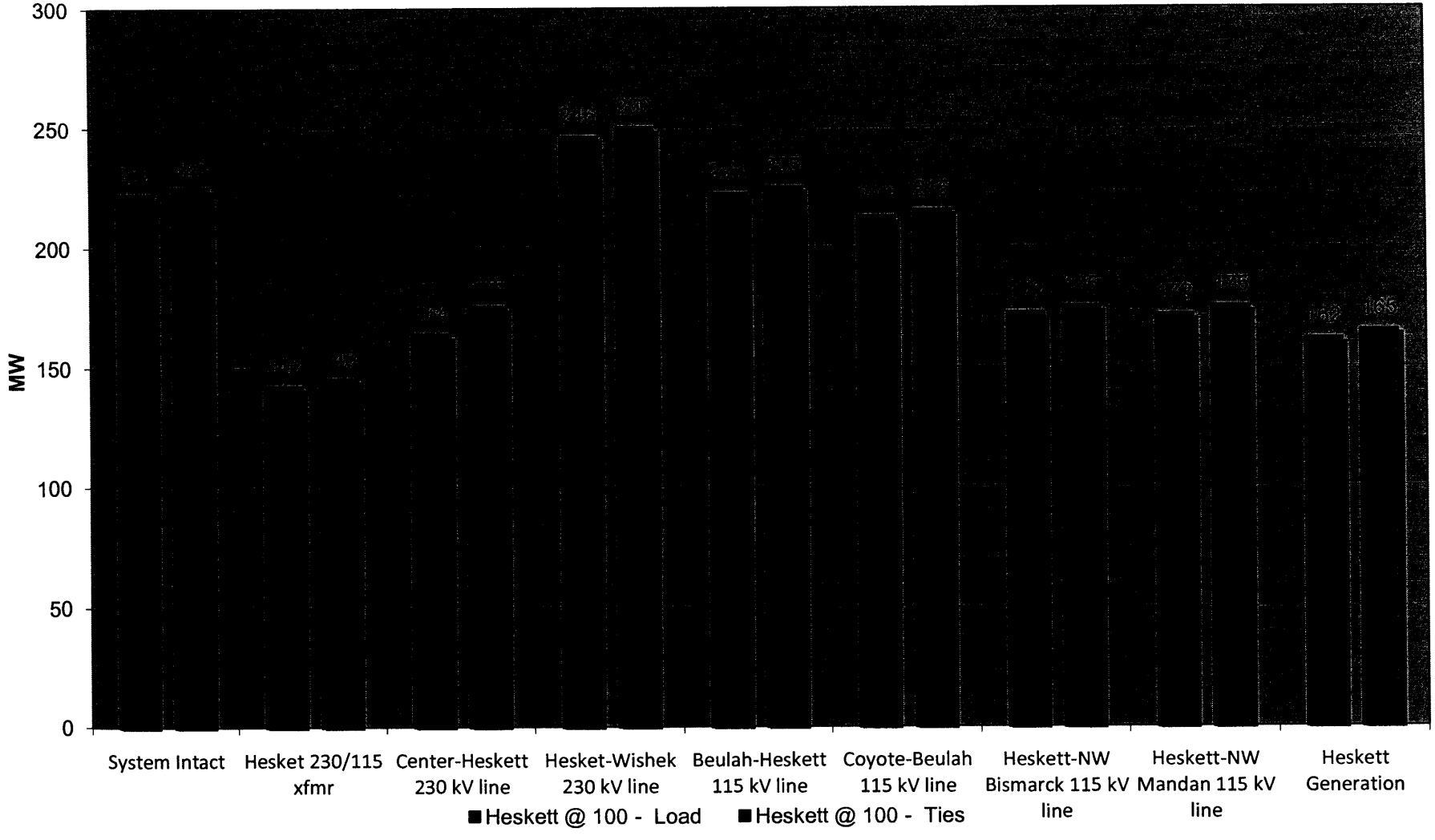
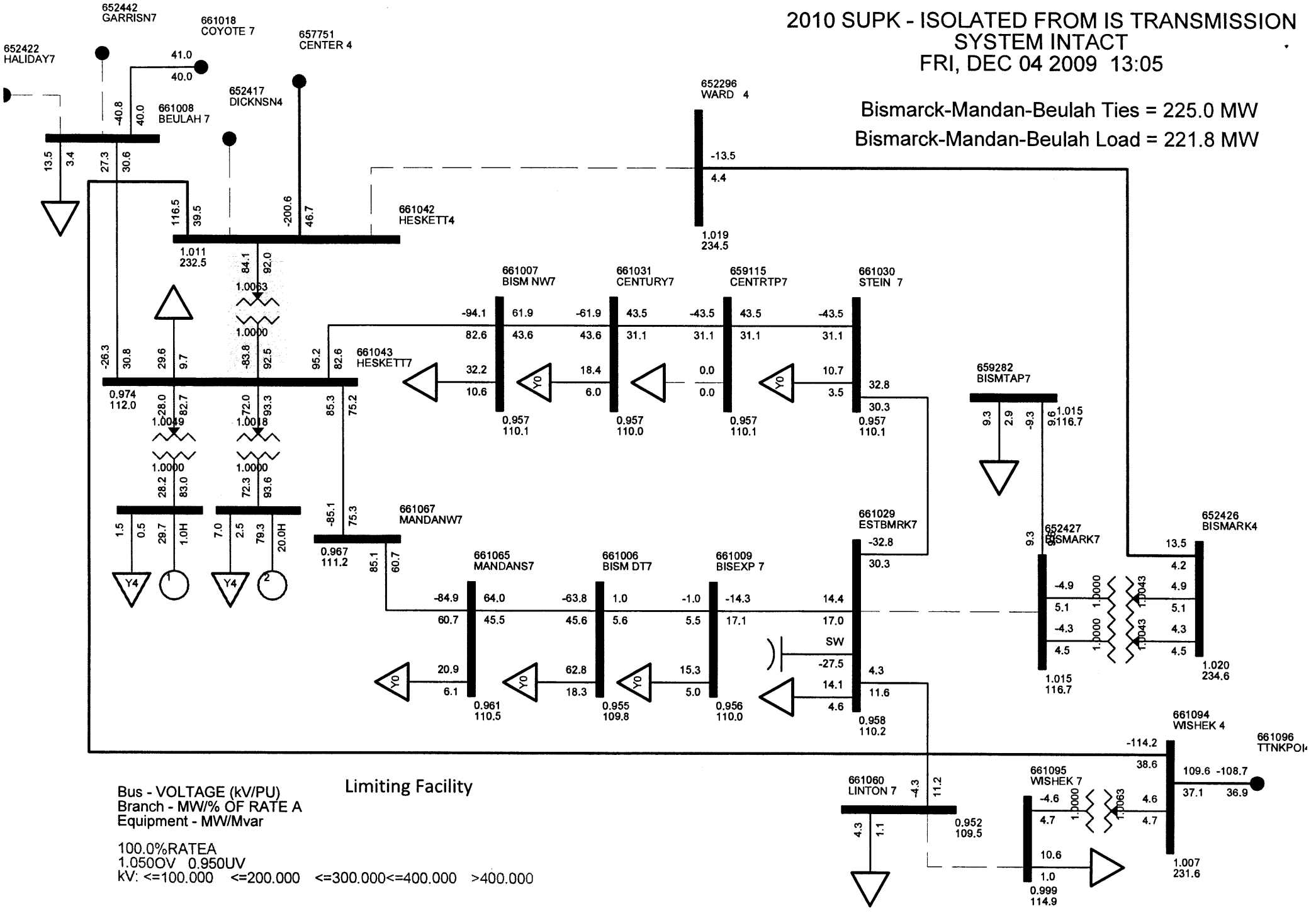
661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
661008 BEULAH 7
652417 DICKNSN4
652296 WARD 4
661042 HESKETT4
661007 BISM NW7
661031 CENTURY7
659115 CENTRTP7
661030 STEIN 7
661043 HESKETT7
659282 BISMTAP7
661067 MANDANW7
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661029 ESTBMRK7
652427 BISMARK7
652426 BISMARK4
661094 WISHEK 4
661096 TTNKPOI
661060 LINTON 7
661095 WISHEK 7
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE B
Equipment - MW/Mvar
Limiting Facility
100.0%RATEB
1.050OV 0.900UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000

Appendix B

Heskett Generation Online at 100 MW

MDU Load Serving Capabilities - Heskett Gen. @ 100
Bismarck-Mandan-Beulah

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Bismarck-Mandan-Beulah Ties = 225.0 MW
Bismarck-Mandan-Beulah Load = 221.8 MW
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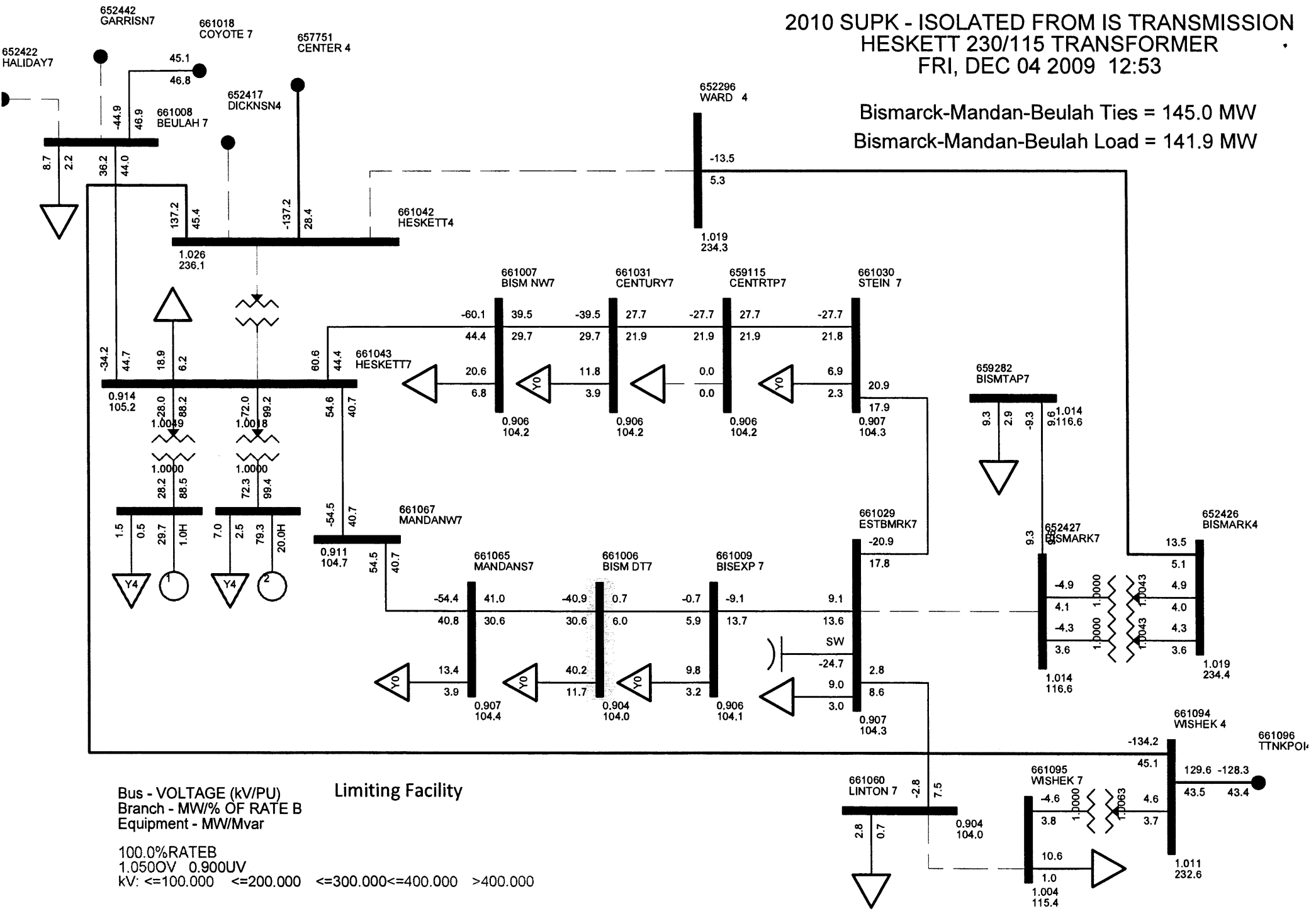
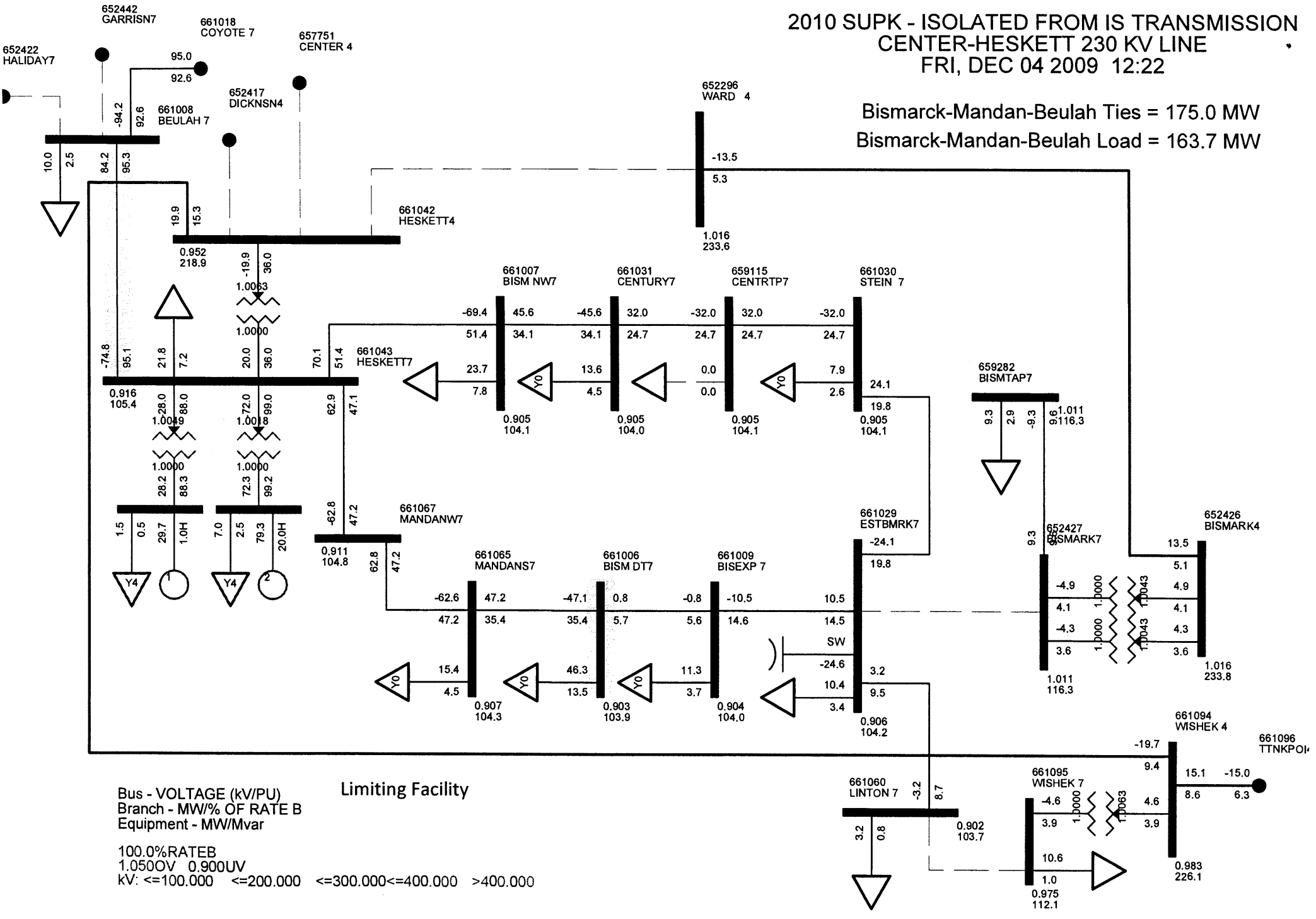
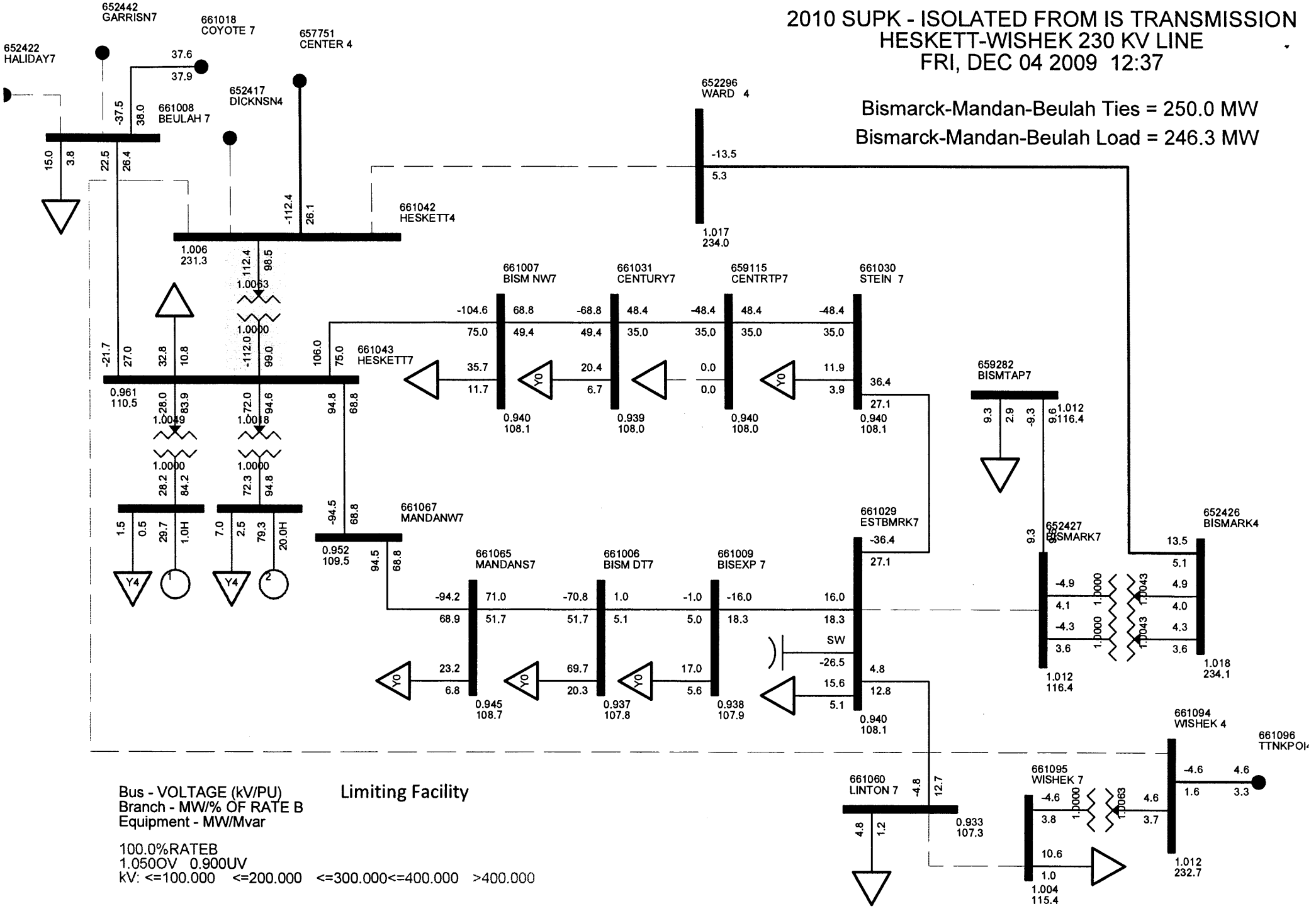
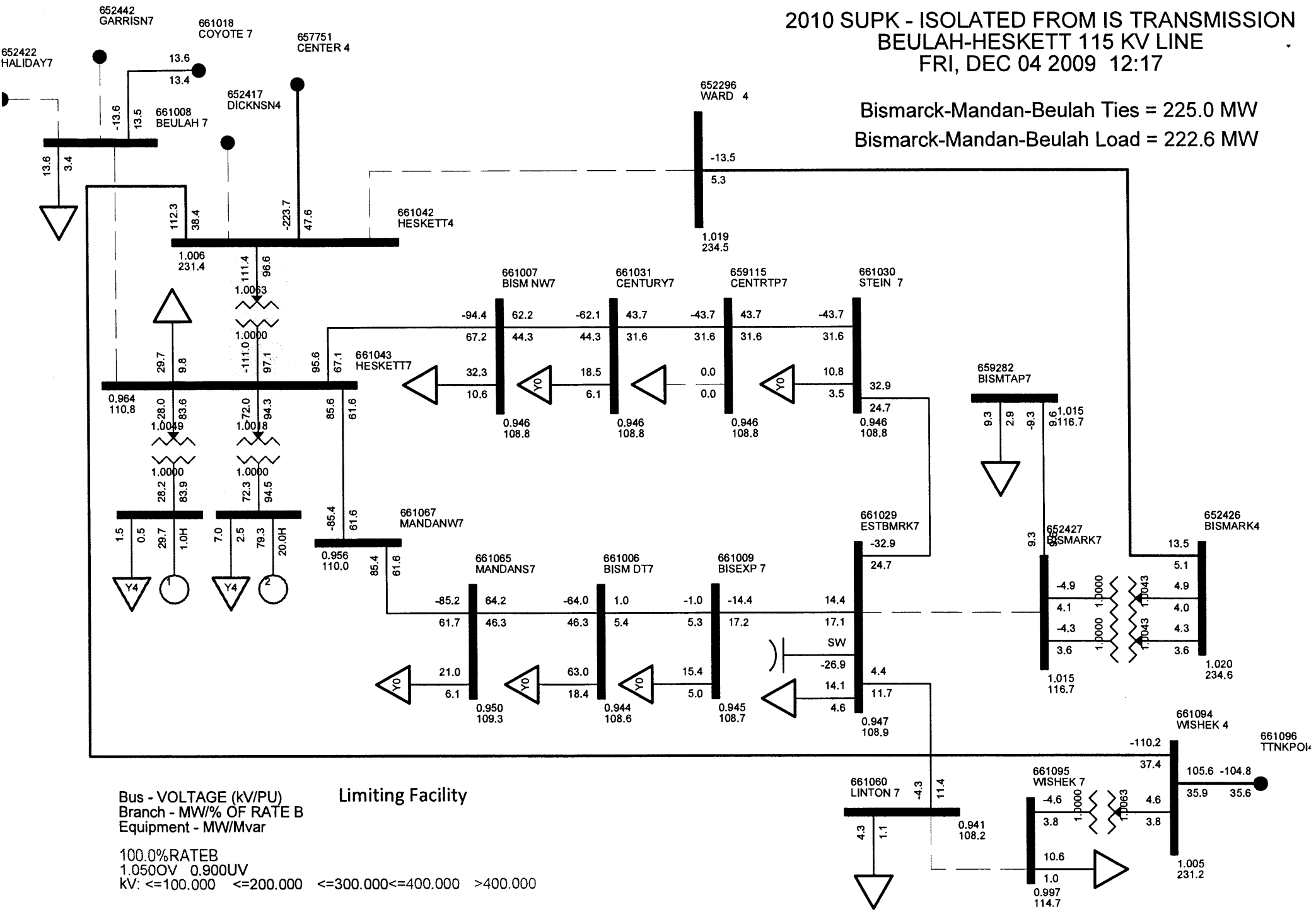
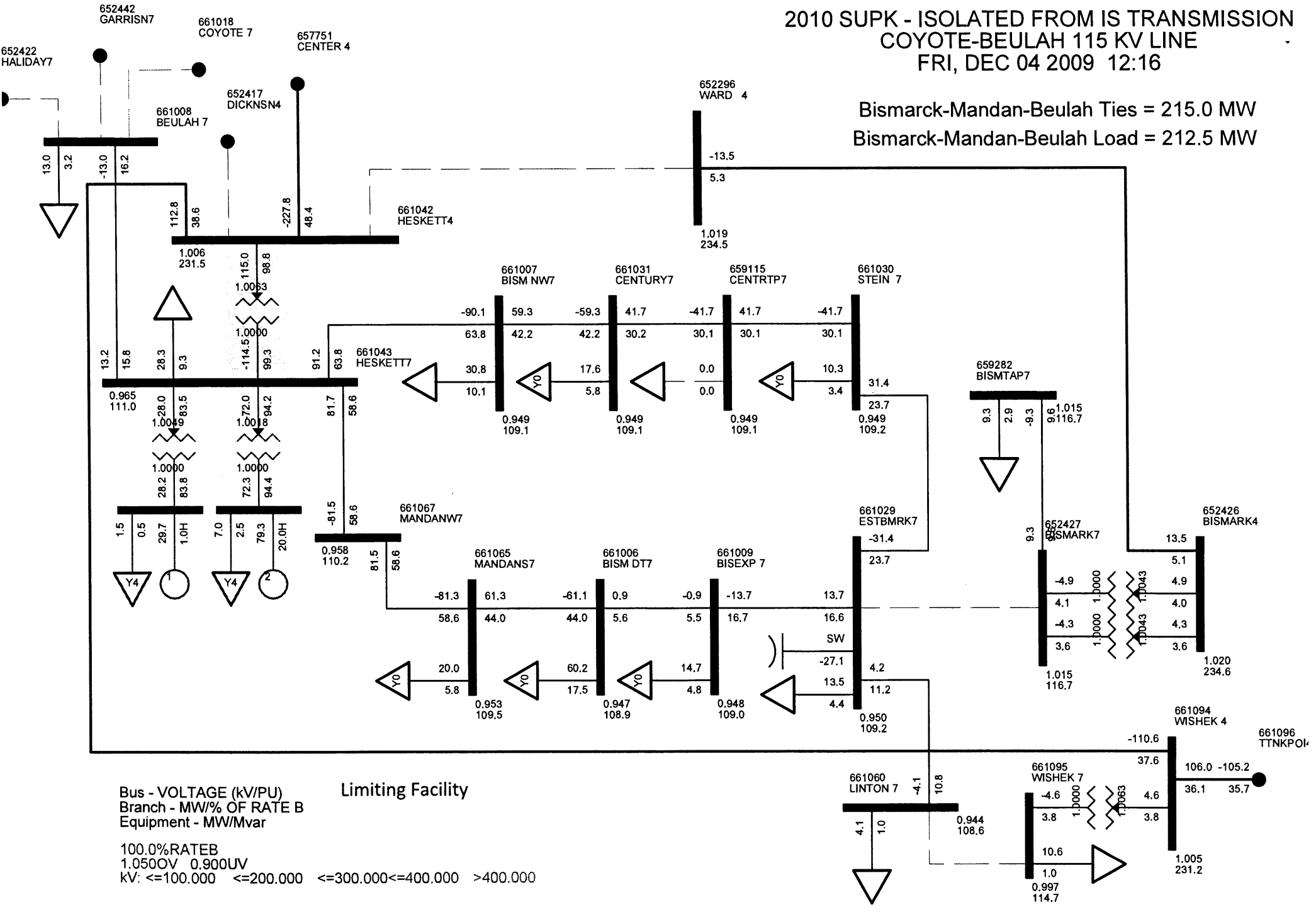
661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
652417 DICKNSN4
661008 BEULAH 7
652296 WARD 4
661042 HESKETT4
661007 BISM NW7
661031 CENTURY7
659115 CENTRTP7
661030 STEIN 7
661043 HESKETT7
659282 BISMTAP7
661067 MANDANW7
661029 ESTBMRK7
652427 BISMARK7
652426 BISMARK4
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661094 WISHEK 4
661096 TTNKPOI
661060 LINTON 7
661095 WISHEK 7
Limiting Facility
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE A
Equipment - MW/Mvar
100.0%RATEA
1.050OV 0.950UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000

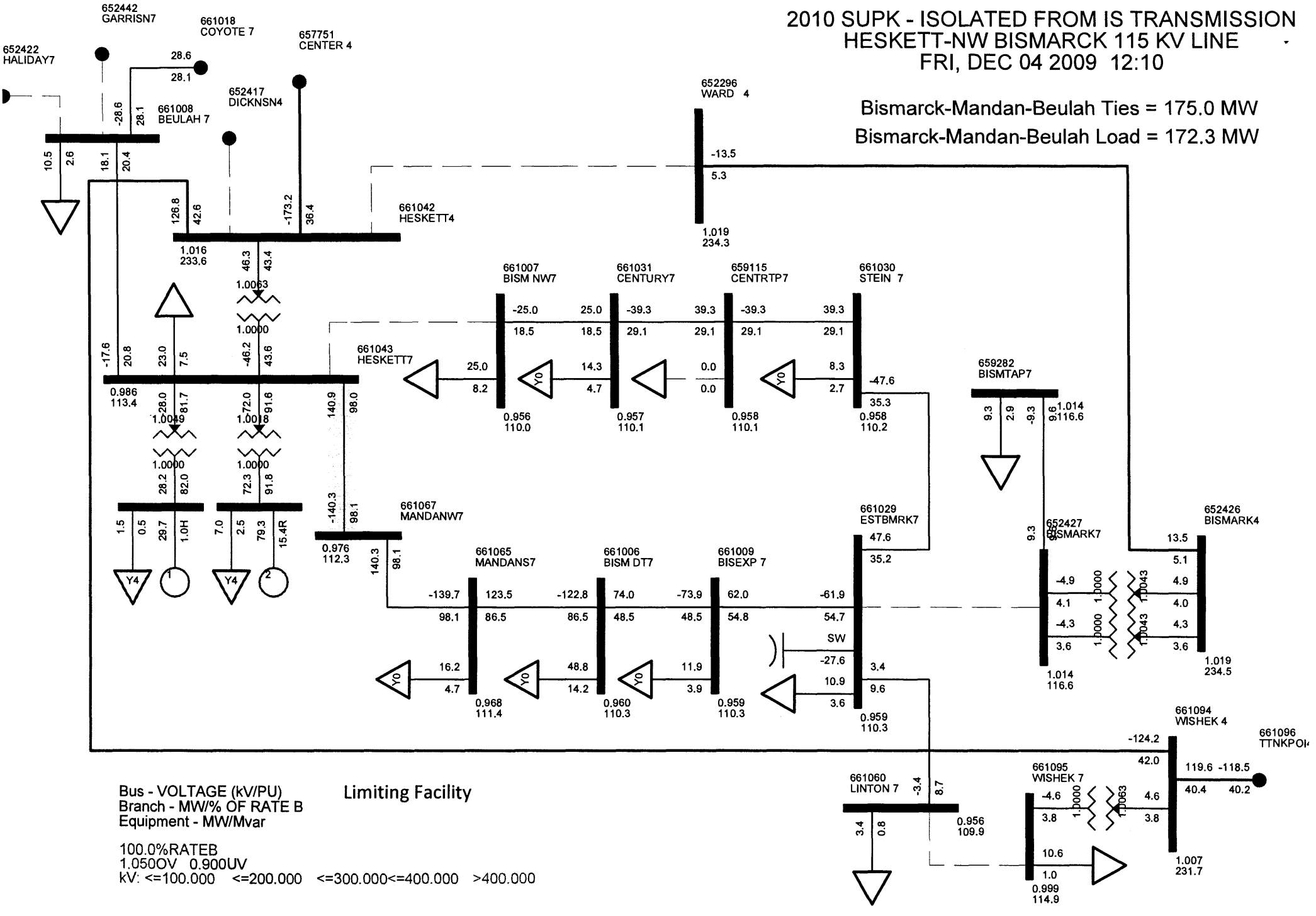

2010 SUPK - ISOLATED FROM IS TRANSMISSION
HESKETT 230/115 TRANSFORMER
FRI, DEC 04 2009 12:53
Bismarck-Mandan-Beulah Ties = 145.0 MW
Bismarck-Mandan-Beulah Load = 141.9 MW
652442 GARRISN7
661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
661008 BEULAH 7
652417 DICKNSN4
652296 WARD 4
661042 HESKETT4
661007 BISM NW7
661031 CENTURY7
659115 CENTRTP7
661030 STEIN 7
661043 HESKETT7
659282 BISMTAP7
661067 MANDANW7
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661029 ESTBMRK7
652427 BISMARK7
652426 BISMARK4
661094 WISHEK 4
661096 TTNKPOI
661095 WISHEK 7
661060 LINTON 7
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE B
Equipment - MW/Mvar
Limiting Facility
100.0%RATEB
1.050OV 0.900UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000

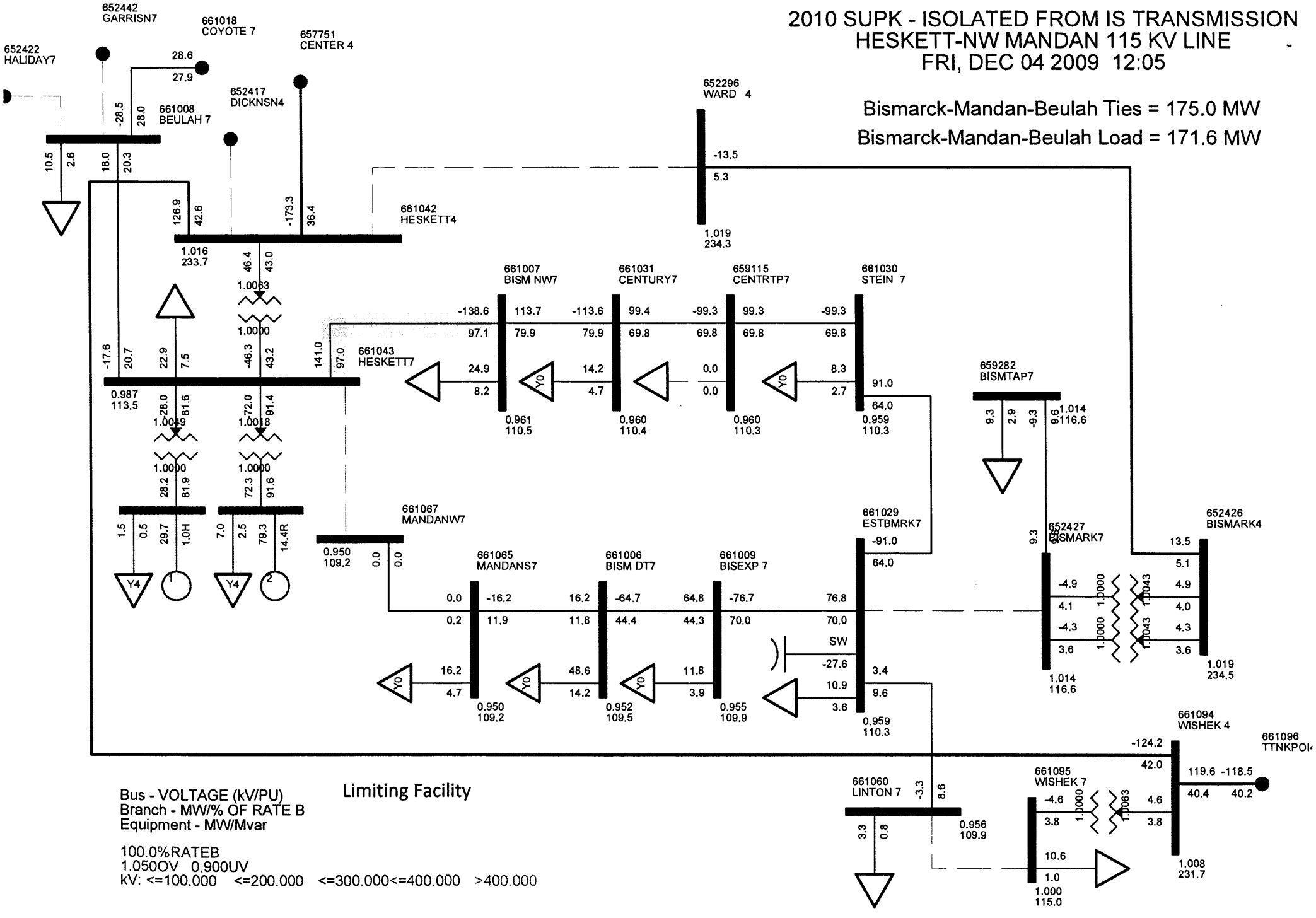

2010 SUPK - ISOLATED FROM IS TRANSMISSION
CENTER-HESKETT 230 KV LINE
FRI, DEC 04 2009 12:22
Bismarck-Mandan-Beulah Ties = 175.0 MW
Bismarck-Mandan-Beulah Load = 163.7 MW
652442 GARRISN7
661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
652417 DICKNSN4
661008 BEULAH 7
652296 WARD 4
661042 HESKETT4
661007 BISM NW7
661031 CENTURY7
659115 CENTRTP7
661030 STEIN 7
661043 HESKETT7
659282 BISMTAP7
661067 MANDANW7
661029 ESTBMRK7
652427 BISMARK7
652426 BISMARK4
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661094 WISHEK 4
661096 TTNKPOI
661060 LINTON 7
661095 WISHEK 7
Limiting Facility
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE B
Equipment - MW/Mvar
100.0%RATEB
1.050OV 0.900UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000

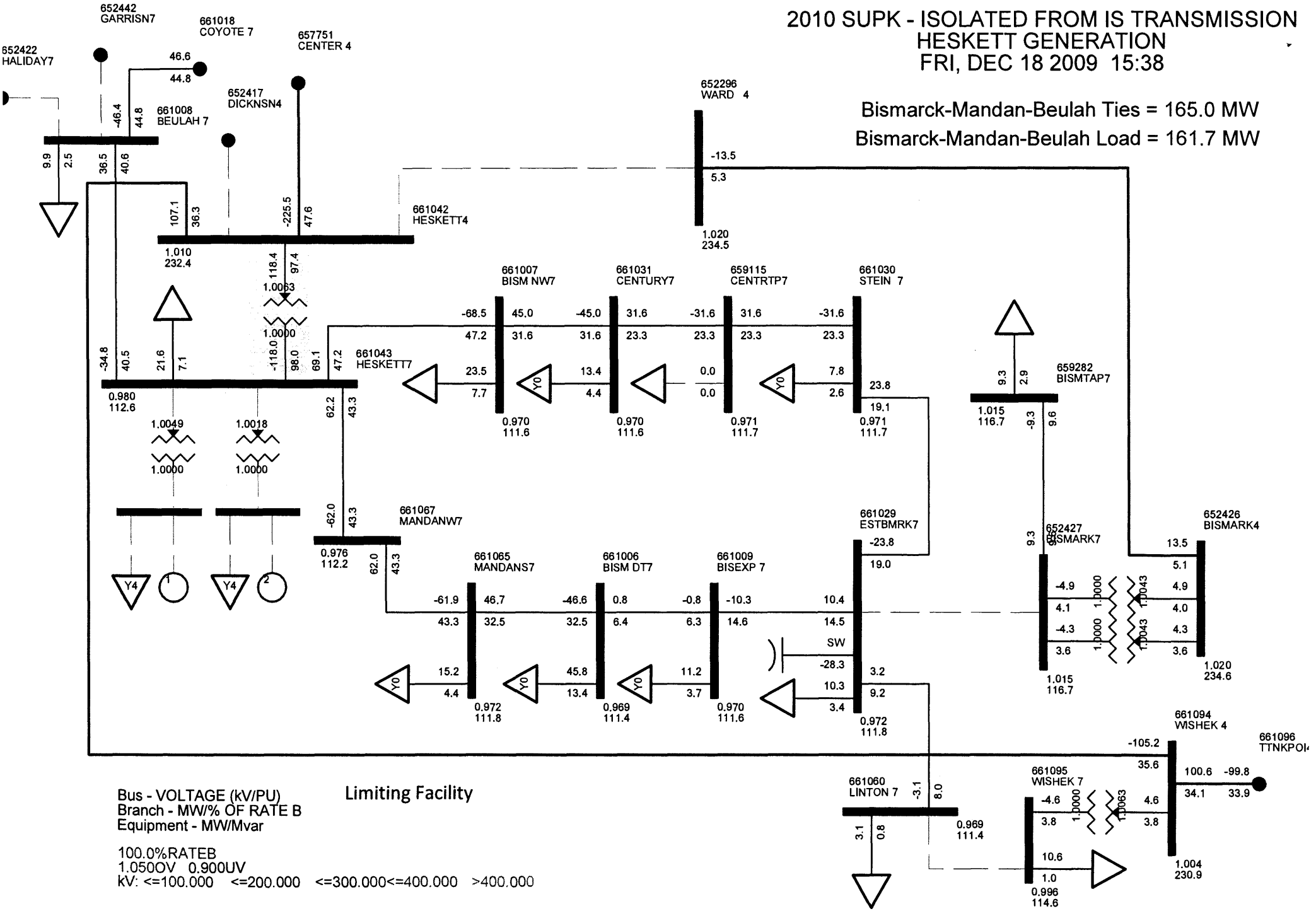

2010 SUPK - ISOLATED FROM IS TRANSMISSION
HESKETT-WISHEK 230 KV LINE
FRI, DEC 04 2009 12:37
Bismarck-Mandan-Beulah Ties = 250.0 MW
Bismarck-Mandan-Beulah Load = 246.3 MW
652442 GARRISN7
661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
661008 BEULAH 7
652417 DICKNSN4
652296 WARD 4
661042 HESKETT4
661007 BISM NW7
661031 CENTURY7
659115 CENTRTP7
661030 STEIN 7
661043 HESKETT7
659282 BISMTAP7
661067 MANDANW7
661029 ESTBMRK7
652427 BISMARK7
652426 BISMARK4
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661094 WISHEK 4
661096 TTNKPOI
661060 LINTON 7
661095 WISHEK 7
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE B
Equipment - MW/Mvar
Limiting Facility
100.0%RATEB
1.050OV 0.900UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000


2010 SUPK - ISOLATED FROM IS TRANSMISSION
BEULAH-HESKETT 115 KV LINE
FRI, DEC 04 2009 12:17
Bismarck-Mandan-Beulah Ties = 225.0 MW
Bismarck-Mandan-Beulah Load = 222.6 MW
652442 GARRISN7
661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
652417 DICKNSN4
661008 BEULAH 7
652296 WARD 4
661042 HESKETT4
661007 BISM NW7
661031 CENTURY7
659115 CENTRTP7
661030 STEIN 7
661043 HESKETT7
659282 BISMTAP7
661067 MANDANW7
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661029 ESTBMRK7
652427 BISMARK7
652426 BISMARK4
661094 WISHEK 4
661096 TTNKPOI
661060 LINTON 7
661095 WISHEK 7
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE B
Equipment - MW/Mvar
Limiting Facility
100.0%RATEB
1.050OV 0.900UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000


2010 SUPK - ISOLATED FROM IS TRANSMISSION
COYOTE-BEULAH 115 KV LINE
FRI, DEC 04 2009 12:16
Bismarck-Mandan-Beulah Ties = 215.0 MW
Bismarck-Mandan-Beulah Load = 212.5 MW
652442 GARRISN7
661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
652417 DICKNSN4
661008 BEULAH 7
652296 WARD 4
661042 HESKETT4
661007 BISM NW7
661031 CENTURY7
659115 CENTRTP7
661030 STEIN 7
661043 HESKETT7
659282 BISMTAP7
661067 MANDANW7
661029 ESTBMRK7
652427 BISMARK7
652426 BISMARK4
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661094 WISHEK 4
661096 TTNKPOI
661095 WISHEK 7
661060 LINTON 7
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE B
Equipment - MW/Mvar
Limiting Facility
100.0%RATEB
1.050OV 0.900UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000


2010 SUPK - ISOLATED FROM IS TRANSMISSION
HESKETT-NW BISMARCK 115 KV LINE
FRI, DEC 04 2009 12:10
Bismarck-Mandan-Beulah Ties = 175.0 MW
Bismarck-Mandan-Beulah Load = 172.3 MW
652442 GARRISN7
661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
661008 BEULAH 7
652417 DICKNSN4
652296 WARD 4
661042 HESKETT4
661007 BISM NW7
661031 CENTURY7
659115 CENTRTP7
661030 STEIN 7
661043 HESKETT7
659282 BISMTAP7
661067 MANDANW7
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661029 ESTBMRK7
652427 BISMARK7
652426 BISMARK4
661094 WISHEK 4
661096 TTNKPOI
661060 LINTON 7
661095 WISHEK 7
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE B
Equipment - MW/Mvar
Limiting Facility
100.0%RATEB
1.050OV 0.900UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000


2010 SUPK - ISOLATED FROM IS TRANSMISSION
HESKETT-NW MANDAN 115 KV LINE
FRI, DEC 04 2009 12:05
Bismarck-Mandan-Beulah Ties = 175.0 MW
Bismarck-Mandan-Beulah Load = 171.6 MW
652442 GARRISN7
661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
661008 BEULAH 7
652417 DICKNSN4
652296 WARD 4
661042 HESKETT4
661007 BISM NW7
661031 CENTURY7
659115 CENTRTP7
661030 STEIN 7
661043 HESKETT7
659282 BISMTAP7
661067 MANDANW7
661029 ESTBMRK7
652427 BISMARK7
652426 BISMARK4
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661094 WISHEK 4
661096 TTNKPOI
661095 WISHEK 7
661060 LINTON 7
Limiting Facility
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE B
Equipment - MW/Mvar
100.0%RATEB
1.050OV 0.900UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000


2010 SUPK - ISOLATED FROM IS TRANSMISSION
HESKETT GENERATION
FRI, DEC 18 2009 15:38
Bismarck-Mandan-Beulah Ties = 165.0 MW
Bismarck-Mandan-Beulah Load = 161.7 MW
652442 GARRISN7
661018 COYOTE 7
657751 CENTER 4
652422 HALIDAY7
652417 DICKNSN4
661008 BEULAH 7
652296 WARD 4
661042 HESKETT4
661007 BISM NW7
661031 CENTURY7
659115 CENTRTP7
661030 STEIN 7
659282 BISMTAP7
661043 HESKETT7
661067 MANDANW7
661029 ESTBMRK7
652427 BISMARK7
652426 BISMARK4
661065 MANDANS7
661006 BISM DT7
661009 BISEXP 7
661094 WISHEK 4
661096 TTNKPOI
661060 LINTON 7
661095 WISHEK 7
Bus - VOLTAGE (kV/PU)
Branch - MW/% OF RATE B
Equipment - MW/Mvar
Limiting Facility
100.0%RATEB
1.050OV 0.900UV
kV: <=100.000 <=200.000 <=300.000<=400.000 >400.000

WAPA Transmission Service Calculation

- Divide system into approximately 20 load pockets
- Using Siemens' PSSE transmission modeling software
  - Disconnect Montana-Dakota system from the WAPA IS System
  - Determine system intact load serving capability with and without generation running
  - Determine system load serving capability with various single contingency outages
- Loads above system capability with limiting contingency would require WAPA IS service
- A local generation resource would offset the need for WAPA IS transmission service

US Department of Energy

Upper Great Plains

Western Area Power Administration

Integrated Transmission System (IS)

Network and Point-to-Point (P-t-P) Transmission and Ancillary/Interconnected

Operations Services Rates and Losses
Effective 01/01/2010

Letter to Customers 12/29/2009

Integrated Transmission System Network and Point-to-Point (P-t-P) Rates and Losses

Transmission Service Type	Network Load Ratio Share	Yearly Firm P-t-P	Monthly Firm P-t-P	Weekly Firm P-t-P	Daily Firm P-t-P	Monthly Non-Firm P-t-P	Weekly Non-Firm P-t-P	Daily Non-Firm P-t-P	Hourly Non-Firm P-t-P
Price	$13,626,770.92/month	$35,520/Mw Year	$2,960/Mw Month	$683.08/Mw Week	$97.58/Mw Day	$2,960/Mw Month	$683.08/Mw Week	$97.58/Mw Day	$4.05/Mw Hour
Losses	4% (8)								

Ancillary/Interconnected Operations Services Rates

Service Type	Scheduling, System Control and Dispatch (1)	Reactive Supply and Voltage Control from Generation Sources (2)			Regulation and Frequency Response (3)			Unreserved Use Penalty (10)
Price	$44.59 per Tag per Day	$50/Mw Month	$11.54/Mw Week	$1.65/Mw Day	6.8 cents/Mw Hour	$50/Mw Month	$11.54/Mw Week	$1.65/Mw Day	200%

Ancillary/Interconnected Operations Services Rates

Service Type	Energy Imbalance (4)	Generator Imbalance (9)	Operating Reserves - Spinning Reserve (5), Supplemental Reserve (6)		
Price	i) For deviations within +/- 1.5% (min of 2 MW) of the scheduled transaction, 100% of average incremental cost; ii) For deviations greater than +/- 1.5% up to 7.5% (or greater than 2 MW up to 10 MW) of the scheduled transaction, 110% of the incremental cost when energy taken is greater than energy scheduled and 90% of the incremental cost when energy taken is less than scheduled; iii) For deviations greater than +/- 7.5% (or 10 MW) of the scheduled transaction, 125% of incremental cost when energy taken is greater than energy scheduled and 75% of incremental cost when energy taken is less than scheduled.	i) For deviations within +/- 1.5% (min of 2 MW) of the scheduled transaction, 100% of average incremental cost; ii) For deviations greater than +/- 1.5% up to 7.5% (or greater than 2 MW up to 10 MW) of the scheduled transaction, 110% of the incremental cost when energy delivereid is less than energy scheduled and 90% of the incremental cost when energy delivered is greater than scheduled; iii) For deviations greater than +/- 7.5% (or 10 MW) of the scheduled transaction, 125% of incremental cost when energy delivered is less than energy scheduled and 75% of incremental cost when energy delivered is greater than scheduled. As an exception, an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5% or 2 MW.	$180/Mw Month for each	$41.54/Mw Week for each	$5.93/Mw Day each

Notes

(1) As per Western's Open Access Transmission Service Tariff, the Western Area Power Administration - Upper Great Plains Region (WAPA) will charge a Scheduling, System Control, and Dispatch (S&D) Ancillary Service fee for all transactions that involve the movement of energy into, out of or through the Upper Great Plains Region control area(s).

In applying the S&D fee the following notes of clarification will be applied:

A. A Scheduling, System Control, and Dispatch (S&D) Fee for MAPP Service Schedule F will be applied in accordance with the Mid-Continent Area Power Pool (MAPP) tariff. Whomever purchases MAPP Service Schedule F transmission (listed as the Company under Customer Information on the OASIS request) for the movement of energy into, out of, or through the WAPA control area(s) will be assessed an S&D fee (see exception in item "E" below).

B. There is no additional S&D fee applied for transmission purchased under the WAPA tariff, as this fee is currently included in the transmission rate.

C. An S&D fee will be applied to those transactions that use transmission other than the WAPA tariff or MAPP F tariff but still require the movement of energy into, out of or through the WAPA control area.

D. The S&D fee is based on one fee per OASIS request per day. Multiple OASIS requests will each have their own S&D fee assessed.

E. MAPP has waived Schedule F transmission service charges for transmission purchases by, or deliveries to, the WAPA Network Service Customers. As such, WAPA will not assess an S&D fee for MAPP Schedule F purchases or deliveries that meet the same requirement, regardless of the transmission customer. These purchases serve Network load and would normally require Network service from Non-designated resources (a transmission product that MAPP does not currently offer), which would not incur any additional fee. Purchases from, or Deliveries from, these Network customers will be assessed an S&D fee based on the transmission customer on the OASIS request.

(2) Reactive Supply and Voltage Control from Generation Sources Service is Mandatory (provided by WAPA) and must be purchased when purchasing transmission under the Western Tariff. The charge is based on the following:

A. Point-to-Point Transmission Service Customers
(i) The Transmission Reservation, not the energy schedule.

B. Other Customers with Load inside of the Control Area
(i) The Transmission Customer's metered Load(s), or calculated Load(s) (if meters are not available), or a combination of the metered and calculated Load(s) (when some meters are available), each Month at the time of the WAPA transmission system peak.

This fee is not assessed for transmission using MAPP Service Schedule F.

(3) Regulation and Frequency Response Service is Required (provided by the WAPA, self provided, or provided by a third party) for all Customers with Load inside the Control Area. The charge is based on the following:

A. The Transmission Customer's metered Load(s), or calculated Load(s) (if meters are not available), or a combination of the metered and calculated Load(s) (when some meters are available), each Month at the time of the WAPA transmission system peak.

(4) Energy Imbalance Service is provided when a difference occurs between scheduled and actual delivery of energy to a load located within Western's Control Areas over a single hour. The Transmission Customer must either obtain this service from Western or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. Western may charge a Transmission Customer a penalty for either hourly energy imbalances under Schedule UG–AS4 or hourly generator imbalances under Rate Schedule UGP–AS7 for imbalances occurring during the same hour, but not both, unless the imbalances aggravate rather than offset each other.

Note: Western has elected to delay charging (financial settlement) for the new Energy Imbalance until such time as certain billing procedures are finalized. Prior to charging and billing for these services, notice of Western's intent to initiate charging will be posted to Western's OASIS web site. Until the new financial settlement of Energy Imbalance is implemented, monthly energy imbalance accounts will be maintained, as in the past. These accounts will be repaid within the following month. This imbalance is determined by comparing the actual generation and/or scheduled energy to the metered Load(s), (or calculated Load(s) if meters are not available), or a combination of the metered and calculated Load(s) (when some meters are available).

(5) Operating Reserve - Spinning Reserve Service (service needed to serve load immediately in the event of a system contingency) is Required (provided by WAPA, self provided, or provided by a third party) for all Customers with Load inside the Control Area. The Charge is based on the following:

A. The Transmission Customer's metered Load(s), or calculated Load(s) (if meters are not available), or a combination of the metered and calculated Load(s) (when some meters are available), each month at the time of the WAPA transmission system system peak. These charges are for providing the service. If energy is actually supplied, UGPR will assess a charge for energy used at the prevailing market energy rate in the region.

6) Operating Reserve - Supplemental Reserve Service (Service needed to serve load in the event of a system contingency; that is not available immediately to serve load, but is available within a short period of time) is Required (provided by WAPA, self provided, or provided by a third party) for all Customers with Load inside the Control Area. The Charge is based on the following:

A. The Transmission Customer's metered Load(s), or calculated Load(s) (if meters are not available), or a combination of the metered and calculated Load(s) (when some meters are available), each month at the time of the WAPA transmission system system peak. These charges are for providing the service. If energy is actually supplied, UGPR will assess a charge for energy used at the prevailing market energy rate in the region.

(7) **These rates are recalculated each year, with any changes taking effect normally on Jan 1st. Unless superceded, these Transmission Service Rate Schedules shall remain in effect until December 31, 2014 (per 12/29/2009 Federal Register Notice).**

(8) Losses for schedules within, through, into, or out of Western's East Control Area (WAUE) are to be delivered to the WAUE control area. Losses for schedules within, through, into, or out of Western's West Control Area (WAUW) that do not meet the above requirements shall be delivered to the WAUW control area. **Transfer capability must be sufficient on constrained paths to allow for delivery of losses across such interfaces, if desired by a transmission customer, and a transmission reservation for delivery of the losses will be required to reserve necessary ATC on constrained paths.** There will be no charge under Western's Tariff for the additional transmission capacity required to supply Western's losses. The losses required, will be supplied based on the following procedures:

A. Losses are based on the energy scheduled, not the reservation.
An energy schedule is directly related to its associated tagged transaction. Per WECC rules, losses for transactions within the WECC region (including Westerns WAUW BA) are required to be accounted for via separate tagged transactions. Therefore for transactions within WECC, individual loss schedules (tagged transactions) for WAPA transmission losses are required for each energy schedule (tagged transaction).
B. A minimum of 1 MW of losses will be supplied for all energy transactions.
C. Losses for On-peak energy schedules will be supplied On-peak, and losses supplied for Off-peak energy schedules will be supplied Off-peak. These losses should also be supplied on a percentage basis during the same hour(s) the energy is scheduled.
D. Losses for <u>any</u> single hour energy schedules = .04 (the current loss percentage) X the energy scheduled (rounded to the nearest whole number, with a 1 MW minimum), and are to be supplied during that same hour.
E. Losses for <u>any</u> multiple hour energy schedules =
Off-peak losses = .04 (the current loss percentage) X the total off peak energy scheduled (rounded to the nearest whole number, with a 1 MW minimum)
On-peak losses = .04 (the current loss percentage) X the total on peak energy scheduled (rounded to the nearest whole number, with a 1 MW minimum)
F. An extension or adjustment of a specific tagged transaction (energy schedule) is still considered one energy schedule.

(9) Generator Imbalance Service is provided when a difference occurs between the output of a generator located within the Transmission Provider's Control Area and a delivery schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area over a single hour. Western will offer this service, to the extent that it is feasible to do so from its own resources or from resources available to it, when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from Western or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. Western may charge a Transmission Customer a penalty for either hourly generator imbalances under this Schedule UG–AS7 or hourly energy imbalances under Rate Schedule UGP– AS4 for imbalances occurring during the same hour, but not both, unless the imbalances aggravate rather than offset each other. Intermittent generators serving load outside Western's Control Area will be required to pseudo-tie or dynamically schedule their generation to another Control Area. An intermittent resource, for the limited purpose of these Rate Schedules, is an electric generator that is not dispatchable and cannot store its fuel source and, therefore, cannot respond to changes in demand or respond to transmission security constraints.

Note: Western has elected to delay charging (financial settlement) for the new Generator Imbalance until such time as certain billing procedures are finalized. Prior to charging and billing for these services, notice of Western's intent to initiate charging will be posted to Western's OASIS web site. Until the new financial settlement of Generator Imbalance is implemented, monthly energy imbalance accounts will be maintained, as in the past. These accounts will be repaid within the following month.

(10) Unreserved Use of Transmission Service is provided when a Transmission Customer uses transmission service that it has not reserved or uses transmission service in excess of its reserved capacity. A Transmission Customer that has not secured reserved capacity or exceeds its firm or non-firm reserved capacity at any point of receipt or any point of delivery will be assessed Unreserved Use Penalties under new Rate Schedule UGP–TSP1. Charge is 200% of the transmission service rate for point-to-point service assessed as follows: the penalty for a single hour will be based upon the rate for daily firm point-to-point service; the penalty for more than one assessment of a given duration (e.g. daily) will increase to the next longest duration (e.g. weekly); the penalty charge for multiple instances of unreserved use within a day will be based on the rate for daily firm point-to-point service; the penalty charge for multiple instances of unreserved use isolated to 1 calendar week would result in a penalty based on the charge for weekly firm point-to-point service; and the penalty charge for multiple instances of unreserved use during more than 1 week during a calendar month is based on the charge for monthly firm point-to-point service.

Back to WAPA OASIS Home Page		**To WAPA Timing Requirements**
www.oatioasis.com/wapa/index.html		www.oatioasis.com/wapa/wapadocs/WAPA-UGPR-Timing-Requirements-Effective-2009-1201.pdf

If you have any questions, please contact: Steve Sanders (WAPA, Billings, MT), (406) 247-7436.
Last Updated on 12/31/2009, By Steve Sanders
Recent Update History:
12/31/09: Rates updated to reflect 12/29/2009 letter to customers and 12/29/2009 Federal Register Notice. Added Unreserved Use Penalty to table, and new Footnote 10. Added new Energy Imbalance and Generator Imbalance to the table, updated Footnote 4 and added new Footnote 9. Foortnotes 5 and 6 updated to reflect UGPR charge at prevailing market energy rate in the region. Footnote 7 updated to reflect change to Jan 1st rate updates, and updated rate schedules effective through 2014.
11/30/09: Footnote 8 updated to clarify losses.

WAPA Transmission Exhibit H Analysis Summar

MDU Analysis (coincident peak)

Point of Delivery	Exhibit H Threshold (kW)	MDU Load (kW) @ peak (7/23/07 1800)	MDU Delta Exceeding	MDU Ties	Co-Op loads
Devaul 69	2900		-2900		
Baker	17000	56603	20003	Baker 230/115 Dawson Cnty-Glendive 115 plus Glendive Gen	Slope - Marmarth, Rhame, Amidon SE Electric - Baker Golden West - North Baker
Glendive	19600	See Baker			N/A
Bowman	3100	4230	1130	Bowman tie	Slope - Bowman, Haley
Culbertson	3100	3167	67	Culbertson tie	Sheridan - Medicine Lake, Froid, Culbertson, N Bainville Lower Yellow - S Bainville, Buford, Dore
Dickinson	30000	48236	6036	Dickinson 230/115 Hettinger 230/115 Coyote-Dickinson115	West Plains - Patterson, New Hradec, Lehigh, Richardton Slope - New England, Acme, Mott
Hettinger	12200	See Dickinson			Slope - Reeder, Haynes, Cedar Butte, Centipede Grand - Lemmon
Glenham	22600	23708	1108	Glenham tie	Cam-Wal - Indian Creek, Shamrock, Pollock, Selby, Java FEM - Tolstoy, Roscoe, Hillsview MGS - McLaughlin Moreau-Grand - McLaughlin, McIntosh, Keldron
Halliday	1100	1381	281	Halliday tie	McKenzie - Werner, Halliday West Plains - Marshall, Dodge
Herbert Weber	1600	2388	788	Herb-Web tie	KEM - Steele, Tappen
Killdeer	1700	2117	417	Killdeer tie	McKenzie - Killdeer
Lewis & Clark	16100	17240	1140	Lewis & Clark 60 plus Lewis & Clark Gen	Lower Yellow - Fairview, Ridgelawn, Crane, Savage Irrigation - Intake
Medora	4500	5083	583	Medora tie	Golden West - Hodges, Wibaux, Golva West Plains - Knudson, Medora, Tracy, Fryburg, Belfield, Schefield
Miles City	19000	27134	8134	Miles City 60 plus Miles City Gen	Irrigation - Kinsey
O'Fallon	1550	300	-1250	O'Fallon tie	N/A
Poplar	6500	5077	-1423	Poplar tie	Sheridan - Brockton, Poplar, N Poplar, Pleasant Prairie Lower Yellow - Brockton Northern - Benrud
Rosebud	5900	6537	637	Rosebud tie	Mid Yellowstone - Rosebud, Horton
Watford City	3700	4943	1243	Watford City tie	N/A
Whitlock	3800	3991	191	Whitlock tie	Cam-Wal - Forest City, Hoven, Whitlock, Lebanon
Williston N.W	32000	41679	9679	Williston-Grenora 115 Williston NW 60 Williston Plant 60 Williston-Zahl 60	Lower Yellow - Trenton Mountrail-Williams - Stony Creek, Missouri Ridge, Zahl Burke-Divide - Twin Buttes, Hanks Sheridan - Grenora, Dagmar, Coalridge, Plentywood, Flaxville, Wolf Creek, Outlook
Wolf Point	5500	6844	1344	Wolf Point	N/A
East Bismarck-Beulah-Hessket	169000	226846	57846	East Bismarck tie Heskett-Dickinson Heskett-Bismarck Center-Heskett Heskett-Wishek Buelah tie Coyote-Beulah 115 plus Heskett Gen	Capital - E Century, East Bismarck, NW Bismarck KEM - Linton MGS - NW Mandan, North Almont, Harmon, Glen Ullin, Heart Butte, Elgin, Devaul, Custer Trail, Plainsview
Kenmare-Tioga	17500	18600	1100	Williston-Tioga 115 Tioga 230/115 Kemanre-Logan 115	Mountrail-Williams - Tioga, Pleasant Valley, Hofflund, Ray, N Tioga 1 & 2, White Earth, Stanley Burke-Divide - Battleview, Crosby, Kincaid, Lignite, Bowbells, Northgate, Niobe, Greenbush, Norma North Central - Sherwood, Mohall

Montana Dakota Utilities Co.
Case Nos. PU-11-395 and PU-11-396
Late Filed Exhibits

Exhibit RSH-12

Provide a copy of the WAPA Transmission Service Agreement and the WAPA Network Transmission Agreement.

An electronic copy of the WAPA Transmission Service Agreement (Contract No. 88-BAO-308 is provided on the enclosed CD.

Please see Attachment A for a copy of the WAPA Network Transmission Agreement. Montana-Dakota's network load amounts billed under this agreement reflect the difference between the load at each delivery point above the amount provided for under the WAPA Transmission Service Agreement (Contract No. 88-BAO-308)

Exhibit RSH-12
Attachment A

ATTACHMENT F

Service Agreement for Network Integration Transmission Service

1.0 This Service Agreement, dated as of July 26th, 2010, is entered into, by and between the Upper Great Plains Region of Western Area Power Administration (Transmission Provider), and Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. ("MDU") (Transmission Customer), each of whom are sometimes hereinafter individually called Party and both are sometimes hereinafter collectively called the Parties. For purposes of this Service Agreement, the Transmission Provider's Transmission Systems consist of the applicable facilities described in Attachment K to the Tariff.

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Network Integration Transmission Service under the Tariff. The Transmission Customer has provided to the Transmission Provider a deposit and nonrefundable application processing fee in accordance with the provisions of Section 29.2 of the Tariff.

3.0 Service under this Service Agreement shall commence on the later of (1) January 1, 2010, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as is mutually agreed. Service under this Service Agreement shall terminate on December 31, 2015 at midnight.

4.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Network Integration Transmission Service in accordance with the provisions of Part III of the Tariff, and this Service Agreement.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:
Operations Manager
Western Area Power Administration
P.O. Box 790
Watertown, SD 57201

Transmission Customer:
Vice-President Electric Supply
Montana-Dakota Utilities Co.
400 North 4th Street
Bismarck, ND 58501

Each Party may change the designation of its representative upon oral notice to the other, with confirmation of that change to be submitted in writing within ten (10) days thereafter.

6.0 The Tariff and the "Specifications for Network Integration Transmission Service" as presently constituted or as they may be revised or superseded are incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

WESTERN AREA POWER ADMINISTRATION

By _____

Title Operations Manager

Address 1330 41st Street SE

Watertown, SD 57201

Date July 26, 2010

MONTANA-DAKOTA UTILITIES, CO., A DIVISION OF MDU RESOURCES GROUP, INC.

By _____ DK

Title VP Electric Supply

Address 400 North Fourth Street

Bismarck, ND 58501

Date 7-19-2010

MDU RESOURCES GROUP, INC. CORPORATE 1924 SEAL DELAWARE

(SEAL)

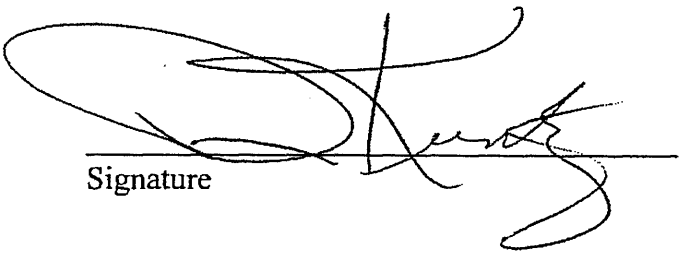
Attest:

By _____

Title Asst. Secretary

CERTIFICATE

I, Daniel S. Kuntz, certify that I am the Assistant Secretary of the Montana-Dakota Utilities Co., the entity named as or Transmission Customer herein; that Andrea L. Stomberg, who signed the above contract on behalf of such Transmission Customer, was then its Vice President-Electric Supply; such contract was duly signed for and in behalf of such Transmission Customer by authority of its governing body and is within the scope of its corporate powers.



Signature

Specifications for Network Integration Transmission Service

For purposes of this Service Agreement, the Transmission Provider's Transmission System consists of the facilities of the Upper Great Plains Region as described in Attachment K.

1.0 The Transmission Provider will provide Network Integration Transmission Service over the Transmission Provider's Transmission System for the delivery of capacity and energy from the Transmission Customer's designated Network Resources to the Transmission Customer's designated Network Load. The Transmission Provider will also provide non-firm transmission service from non-designated Network Resources under the terms of this Service Agreement. The loss factors associated with this Network Integration Transmission Service are set forth below. Such losses shall be applied and accounted for as set forth in Section 4.

2.0 Designated Network Resources:

Designated Network Resources & Estimated Maximum Resource (MW)	Point of Receipt	Delivering Party & Voltage
Midwest ISO Ancillary Services Market	Transmission Customer System	Transmission Customer & varies
Coyote Station / 106 MW	Coyote Jct. Sub	Transmission Customer & 345-kV
Heskett Station Unit 1 and Unit 2 / 28 MW & 74 MW	Heskett 115-kV & 41.6-kV Switchyard	Transmission Customer & 115-kV
Lewis & Clark Station / 52 MW	Lewis & Clark Jct. Sub	Transmission Customer & 115-kV
Glendive Unit 1 and Unit 2 Combustion Turbines / 35 MW & 41 MW	Glendive Turbine Jct. Sub	Transmission Customer & 115-kV
Miles City Combustion Turbine / 25 MW	Miles City Turbine Jct. Sub	Transmission Customer & 60-kV

3.0 Designated Network Loads:

Designated Network Load & Estimated Maximum Resource (MW)	Point of Delivery & Voltage	Contract No. 88-BAO-308 ("GFA"), Exhibit H Capacity Applied[1] / MDU GFA Transmission Capacity Allocation[2]
Baker Area	Baker 230-kV Dawson County 115-kV	Exhibit H = 36.6 MW (Baker, 17.0 MW; Glendive, 19.6 MW) / MDU Capacity = 35.197 MW
Bismarck Area	The metered quantities on the following transmission facilities will be used to determine the Bismarck Area load: a) The Coyote-Beulah 115-kV Line (metered at Coyote) b) The Beulah Tie Meters (115-kV main and transfer bus at Beulah) c) The Bismarck Tie Meter (Bismarck-East Bismarck 115-kV Line, metered at Bismarck) d) Summation of Heskett-Dickinson 230-kV, Heskett-Ward 230-kV, Heskett-Center 230-kV, and Heskett-Wishek 230-kV (all metered at Heskett) e) Glen Ullin-Dickinson 41.6-kV (metered at Glen Ullin) Transmission Customer's SCADA metering will be utilized in lieu of metering on an interim basis for transmission facilities (a), (d – Heskett-Wishek 230-kV), and (e) until such time as Transmission Customer installs the necessary metering on those facilities. Transmission Customer shall use reasonable efforts to install the necessary metering by December 31, 2011.	Exhibit H = 171.9 MW (Beulah-Bismarck - Heskett, 169.0 MW; Devaul, 2.9 MW)
Bowman Area	Bowman 230-kV	Exhibit H = 3.1 MW (Bowman 3.1 MW) / MDU Capacity =

[1] MDU's Maximum Load Obligation amounts for the Points of Delivery as set forth in Exhibit H made November 3, 1993 (and effective October 1, 1993) as part of Contract 88-BAO-308 dated July 1, 1988, between the Parties.
[2] Allocation under this Service Agreement of the MDU Transmission Capacity amounts set forth in the MDU/WAPA Wheeling Methodology document dated March 14, 1985.

		3.081 MW
Dickinson-Hettinger Area	The metered quantities on the following transmission facilities will be used to determine the Dickinson-Hettinger Area load: a) Coyote-Beulah 115-kV line b) Heskett-Dickinson 41.6-kV line c) Coyote 345/115-kV transformer d) Dickinson 230/115-kV transformer e) Hettinger 230/115-kV transformer	Exhibit H = 42.2 MW (Dickinson 30 MW; Hettinger 12.2 MW)
Culbertson Area	Culbertson 115-kV	Exhibit H = 3.1 MW (Culbertson 3.1 MW)
Dunning Area	Mallard 115-kV	Exhibit H = 0 MW / MDU Capacity = 1.023 MW
Glenham	Glenham 230-kV	Exhibit H = 22.6 MW (Glenham 22.6 MW)
Halliday Area	Halliday 115-kV	Exhibit H = 1.1 MW (Halliday 1.1 MW)
Herbert Weber Area	Herbert Weber 230-kV	Exhibit H = 1.6 MW (Herbert Weber 1.6 MW)
Killdeer Area	Killdeer 115-kV	Exhibit H = 1.7 MW (Killdeer 1.7 MW)
Lewis & Clark Area	Lewis & Clark 60-kV & 13.8-kV	Exhibit H = 16.1 MW (Lewis and Clark 16.1 MW)
Medora Area	Medora 230-kV	Exhibit H = 4.5 MW (Medora 4.5 MW)
Miles City Area	Miles City 57-kV	Exhibit H = 19.0 MW (Miles City 19.0 MW) / MDU Capacity = 9.110 MW
O'Fallon Area	O'Fallon 12.47-kV	Exhibit H = 1.55 MW (O'Fallon 1.55 MW)
Poplar Area	Poplar 115-kV	Exhibit H = 6.5 MW (Poplar 6.5 MW)
Rosebud Area	Rosebud 230-kV	Exhibit H = 5.9 MW (Rosebud 5.9 MW) / MDU Capacity = 2.613 MW
Tioga-Stanley-Kenmare Area	Tioga 230-kV & 115-kV Kenmare 115-kV	Exhibit H = 17.5 MW (Kenmare-Tioga 17.5 MW) / MDU Capacity = 5.581 MW
Watford Area	Watford 34.5-kV	Exhibit H = 3.7 MW (Watford 3.7 MW)
Whitlock Area	Whitlock 230-kV	Exhibit H = 3.8 MW (Whitlock 3.8 MW)
Williston Area	Williston 115-kV & 57-kV	Exhibit H = 32.0 MW (Williston 32.0 MW) / MDU Capacity = 9.996 MW

Wolf Point Area	Wolf Point 34.5-kV	Exhibit H = 5.5 MW (Wolf Point 5.5 MW)

3.1 The Network Load amounts billed under this Service Agreement shall be the remainder of the Transmission Customer's load at each Point of Delivery after subtracting the amount of the Transmission Customer's load provided for under Contract No. 88-BAO-308, Exhibit H, and the associated operating procedures entitled "MDU/WAPA Wheeling Methodology " as mutually agreed by the Parties. Any non-Transmission Customer load and associated losses at these Points of Delivery shall be subtracted from the delivery point load metering.

3.2 For purposes of calculating the Network Load amounts billed under this Service Agreement, MDU's transmission capacity of 16,600 KW in Section II.A of the MDU/WAPA Wheeling Methodology will be allocated amongst the Dunning, Tioga/Kenmare, and Williston Points of Delivery as shown in the Designated Network Loads table above based upon a ratio of the total energy delivered to these MDU loads in calendar year 2009. MDU's transmission capacity of 50,000 kW in Section II.B of the MDU/WAPA Wheeling Methodology shall be allocated amongst the Baker/Glendive, Bowman, Miles City, and Rosebud Creek Points of Delivery as shown in the Designated Network Loads table above based upon the ratio of the total energy delivered to these MDU loads in calendar year 2009.

3.3 The Parties agree to utilize the March 14, 1985, version of the MDU/WAPA Wheeling Methodology operating procedures, with: 1) the MDU interconnections at Halliday, Herbert Weber, and Killdeer added to Section I; 2) The MDU interconnections at Dunning and Tioga added to Section II; 3) the clarification "For purposes of loss calculation and reimbursement, the total MDU energy delivered through the interconnection will be used" added to Section II; and 4) the MDU Monthly Load Factor referenced in Section II.B set to 1.0. MDU will not pay wheeling charges under Contract No. 88-BAO-308 for services received under this Service Agreement.

3.4 Network Loads may be sectionalized to different Points of Delivery by the Transmission Customer on a seasonal basis upon advance notice from the Transmission Customer, and mutual agreement of the Parties, to allow the Transmission Provider to accurately reflect the Network Load in the network service billing.

3.5 Load transfers via emergency interconnection points will be accounted for in the determination of the Transmission Customer's Network Load amount at each Point of Delivery.

4.0 Transmission Losses:

4.1 Loss Factors:

4.1.1 If, based on operating experience and technical studies, the Transmission Provider determines that any of the transmission loss factors on the Transmission Provider's Transmission System differs from the loss factors set forth in this Service Agreement, the Transmission Provider will notify

the Transmission Customer of the revised loss factor(s) pursuant to Section 1.0 of this Service Agreement.

4.1.2 Transmission Provider Transmission Loss Factor: For deliveries to the Transmission Customer Network Load, Transmission Provider transmission losses shall initially be 4 % and shall be assessed on the power scheduled and transmitted to a point of delivery on the Transmission Provider's Transmission System.

4.2 Transmission losses may be revised by written notice from the Transmission Provider to the Transmission Customer.

5.0 The Transmission Customer's transmission facilities that are integrated with the Transmission Provider's Transmission System will receive facility credits under this Service Agreement upon termination of Contract No. 88-BAO-308 between the Parties.

5.1 The amount of the facility credit, if applicable, will be mutually agreed upon by the Parties. The annual amount will be divided by 12 and will be credited to the Transmission Customer's monthly network transmission service payment. The facility credits shall be reviewed and updated annually on January 1st of each year based on the previous year's data.

6.0 Names of any intervening systems with whom the Transmission Customer has arranged for transmission service to the Transmission Provider's Transmission System.

6.1 Midwest ISO
6.2 _____

7.0 Power Factor: The Transmission Customer will be required to maintain a power factor between 95 -percent lagging and 95 -percent leading for all deliveries of capacity and energy to and from the Transmission Provider's Transmission System.

8.0 Ancillary Services

8.1 Provided by Transmission Provider

8.1.1 Scheduling, System Control, and Dispatch Service
8.1.2 Reactive Supply and Voltage Control from Generation Sources Service

8.2 Provided by Transmission Customer

8.2.1 Regulation and Frequency Response Service (as a Market Participant of the Midwest ISO's Ancillary Services Market)
8.2.2 Energy Imbalance Service and Generator Imbalance Service (as a Market Participant of the Midwest ISO's Ancillary Services Market)

8.2.3 Operating Reserve – Spinning Reserve Service (as a Market Participant of the Midwest ISO's Ancillary Services Market)

8.2.4 Operating Reserve – Supplemental Reserve Service (as a Market Participant of the Midwest ISO's Ancillary Services Market)

8.3 Provided by Others

8.3.1 None

9.0 Net Billing and Bill Crediting Option: The Parties have agreed to implement both Net Billing and Bill Crediting, as set forth in Attachment J.

10.0 Charges for Service: Charges for Network Integration Transmission Service and associated Ancillary Services shall be calculated in accordance with the applicable Rate Schedule(s) attached hereto and made a part of this Service Agreement. The rates or rate methodology used to calculate the charges for service under that schedule were promulgated and may be modified pursuant to applicable Federal laws, regulations and policies.

11.0 Independent System Operator: The Parties understand that the Transmission Provider may join an independent system operator under Commission jurisdiction. In the event the Transmission Provider either joins or is required to conform to protocols of the independent system operator, the Parties agree that the Transmission Provider either may (1) make any changes necessary to conform to the terms and conditions required by Commission approval of the independent system operator, or (2) terminate this Service Agreement by providing a one-year written notice to the Transmission Customer.

Rate Schedule UGP-NT1
January 1, 2010
Supersedes 2005 Schedule

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

UPPER GREAT PLAINS REGION
INTEGRATED SYSTEM

ANNUAL TRANSMISSION REVENUE REQUIREMENT FOR NETWORK INTEGRATION TRANSMISSION SERVICE

Effective

January 1, 2010, through December 31, 2014, or until superseded by another rate schedule.

Applicable

The Transmission Customer shall compensate the Upper Great Plains Region (UGPR) each month for Network Transmission Service under the applicable Network Integration Transmission Service Agreement and annual revenue requirement outlined below. The formula for the annual revenue requirement used to calculate the charges for this service under this schedule was developed and may be modified under applicable Federal laws, regulations, and policies.

UGPR may modify the charges for Network Integration Transmission Service upon written notice to the Transmission Customer. Any change to the charges to the Transmission Customer for Network Integration Transmission Service shall be as set forth in a revision to this rate schedule developed under applicable Federal laws, regulations, and policies and made part of the applicable Transmission Customer's Service Agreement. UGPR shall charge the Transmission Customer under the revenue requirement then in effect.

Formula Rate

Monthly Charge =

Transmission Customer's Load-Ratio Share x Annual Revenue Requirement for IS
Transmission Service
12 months

Annual Revenue Requirement

A recalculated annual revenue requirement will go into effect every January 1 based on updated financial data. UGPR will notify the Transmission Customer annually of the recalculated annual revenue requirement on or before September 1.