Appendix C

Method Calculation Example

Appendix C Example Calculation

The mechanics and characteristics of the five methods and the influence of shift assumptions will become clearer by examining the details of calculation with an example.

The example chosen is the Leeds to Pleasant Valley 345 kV line for loss of the parallel Athens to Pleasant Valley 345 kV line. This monitored pair was a significant point of congestion in the New York market in 2005, and thus it merits examination as a deliverability concern.

The details of the various method calculations by reference to the tables in Appendix C. The operations case will be used for this example. See Appendix D for case information.

The flow in the power flow case provided was 1588 MW. The short term emergency (STE) line rating is 1724 MW giving an initial case headroom for this monitored pair of (1724 - 1588) = 136 MW.

Two different shifts are shown in Table C-1, line 1. A zonal generation-to-load shift has an average distribution factor on the monitored pair of 0.1804; a shift to all of NYCA has a shift factor of 0.1039. This means that a NYCA shift of generation to load will impose only about half the flow than a zonal shift. This is expected because the NYCA shift includes the large amount of generation and load in zones J and K, which does not flow across this monitored pair, thus the average shift factor is reduced.

This example calculation will now focus on the NYCA shift column in Table C-1.

Referring to table C-2 on the upstream side (western NY in this case) there were 19,738 MW of generation, 4,289 of which had a less than 4% DFAX on the monitored pair. The downstream side had 20,707 MW of generation, 7,375 with less than a 4% DFAX. Examination of Table C-2 (which shows the most impacting of the generating units) shows that the upstream generator shift factors ranged from Athens at 0.3076 to about 0.1800 for far western New York generators. Downstream generator distribution factors were all about 10% (with exceptions).

In this case, which has no EFORd reductions or load increases as a proxy for uncertainty, the flow effect of increasing all harmer generators to their maximum is an increase of 865 MW (Table C-2, total harmer “impact up”). Bringing the downstream generators to their maximum reduces flow by 411 MW. Bringing all 4 generators up to maximum then will cause a net flow increase of (865 – 411) = 454 MW. When added to the initial flow of 1,588 MW the resultant flow is 2,042 MW. With a 1,724 MW rating this is an overload of 318 MW (negative headroom).

The overload with all helpers and harmers on flags this monitored pair as worthy of further examination. This initial test is done for all monitored elements for all monitored element / contingency combinations (pairs) and for interfaces.

Method 1 Calculation: Derated Unit Outputs

The method 1 calculation proceeds in a very similar fashion to the initial screen described above. Rather than using a generator increase from the power flow output to the unit maximum, the increase is to a lower value defined by the regional EFORd, applied uniformly to all generators. As shown in Table C-1, lines 5 and 6 the helper and harmer impact changes with impact greater than 4% to 684 and -305 MW respectively, resulting in a 244 MW overload.

Method 2 Calculation: PJM-Like Method

In this method the larger impacting generators (Table C-2) are sorted by this impact and are assumed to impose the different harmer or helper impact depending on their location and the cumulative availability. Helper generators always provide full flow reduction impact. The harmer side generators impact is the full maximum incremental amount if the cumulative availability of the harmer generators being summed is greater than 80%. The balance of the 4% impact harmer generators are then considered at 85% of their maximum output.

The result of this calculation is shown in Table C-1, lines 8 and 9. The helper and harmer impact changes to 825 and 411 MW respectively, resulting in a 278 MW overload.

Method 3 Calculation: Load Adjustment as Uncertainty Proxy

In this method the load on the upstream side is increased by 15.9% to represent generation and demand uncertainty. This increase is supplied by upstream and downstream generators.

The net effect of the load increase with generators brought to their full output is shown in Table C-1 lines 11 and 12. The result is a 5 MW headroom.

Method 4 Calculation: Upstream and Downstream Gen-Load Matching

In this method the upstream and downstream regions generation and load is balanced separately and resultant flows are calculated on the monitored pair.

The idea of this calculation is to balance all load and generation upstream and downstream. Table C-1 lines 14 through 16 show that there is 19,738 MW upstream serving a load of 13,503 MW leaving an upstream excess generation available of 6,235 MW. When this 6,235 MW excess is assumed to displace downstream generation the impact on the monitored pair (including the effect of upstream generation serving upstream load), the flow on the monitored pair is 2024 MW (line 20).

Downstream there is 20,707 MW of generation and 23,216 MW load (after the 15.9% increase), leaving a deficit of 2,509 MW (line 19). When the downstream generation serves this downstream load 46 MW of flow is imposed on the monitored pair (line 21).

The remaining component of flow on the monitored pair is non-dispatchable flow from losses, other areas, and PARs. This was 360 MW (line 22). Summing up the upstream, downstream and non-dispatchable flow results in a total flow of 2,431 MW. With a 1724 MW rating, this yields a 707 MW overload (line 24).

<u>Method 5 Calculation: Only Transfer as Much as is Needed</u>

The difference in method 5 is that only the amount of downstream deficit of generation to load is transferred from the upstream surplus. All other calculations are the same.

Lines 19 or 29 in Table C-1 show that the deficit downstream was 2,509. Thus only 2,509 MW of the 6,235 MW available upstream (line 16) will be transferred. This changes the impact of upstream generation being transferred from 2,024 (line 20) in method 4 to 939 MW (line 30), yielding a headroom of 379 MW (line 34).

Notice that for the zonal shift case there was no downstream deficit. Therefore, the upstream impact is only the flow resulting from upstream generation serving upstream load, 144 MW (line 30).

Table C-1

Calculation Details Example
Operations Case
Leeds - PV for Athens PV Contingency

LINE #		Zonal Shift	NYCA Shift	Comments
1	**Average Generation to Load Shift factor**	0.1804	0.1039	
2	**Initial Flow**	1588	1588	From the Power Flow Case
3	**Rating**	1724	1724	From the Power Flow Case
4	**Pre-Test Headroom**	136	136	Rating - Initial Flow
	Method 1 Derated Unit Outputs			
5	Harmer Impact	311	684	From shift factor and generation Increment available
6	Helper Impact	-67	-305	From shift factor and generation Increment available
7	**Headroom**	**-108**	**-244**	Pre-test headroom - helper -harmer impact
	Method 2 PJM-Like Method			
8	Harmer Impact	374	825	From shift factor and generation Increment available
9	Helper Impact	-119	-411	From shift factor and generation Increment available
10	**Headroom**	**-119**	**-278**	Pre-test headroom - helper -harmer impact
	Method 3 Load Adjustment as Uncertainty Proxy			
11	Harmer Impact	172	354	From shift factor and generation Increment available
12	Helper Impact	-28	-223	From shift factor and generation Increment available
13	**Headroom**	**-9**	**5**	Pre-test headroom - net impact
	Method 4 Upstream and Downstream Gen-Load Matching			
14	Upstream Generation	19683	19738	From the Power Flow Case
15	Upstream Load	12998	13503	From the Power Flow Case after load adjustment
16	Upstream Excess Generation	6684	6235	From the Power Flow Case after load adjustment
17	Downstream Generation	5777	20707	From the Power Flow Case
18	Downstream Load	5164	23216	From the Power Flow Case after load adjustment
19	Downstream Deficit Load	0	2509	Generation - Load
20	Upstream Impact	1856	2024	From **upstream excess generation available** and shift factors
21	Downstream Impact	-60	46	From downstream gen and load balance and shift factors
22	Other Areas Flow or PAR effect	1350	360	From the Power Flow Case
23	Total Upstream and Downstream Impact	3146	2431	Net Impact from sum of previous 3 items
24	**Headroom**	**-1422**	**-707**	Pre-test headroom - net impact
	Method 5 Only Transfer as Much as is Needed			
25	Upstream Generation	19683	19738	From the Power Flow Case
26	Upstream Excess Generation Needed	0	2509	Downstream load minus downstrewam generation
27	Downstream Generation	5777	20707	From the Power Flow Case
28	Downstream Load	5164	23216	From the Power Flow Case after load adjustment
29	Downstream Deficit Load	0	2509	Generation - Load
30	Upstream Impact	144	939	From **downstream needed** and shift factors
31	Downstream Impact	-60	46	From downstream gen and load balance and shift factors
32	Other Areas Flow or PAR effect	1350	360	From the Power Flow Case
33	Total Upstream and Downstream Impact	1434	1345	Net Impact from sum of previous 3 items
34	**Headroom**	**290**	**379**	Pre-test headroom - net impact

Table C-2
Monitored Element Details
Operations Case
Leeds - PV for Athens PV Contingency

Limit	Flow	Load%	HeadRm
1724	1588	92.1	136

Zone	<-------------------- HARMERS -------------------->						<-------------------- HELPERS -------------------->					
	N_Harm	HarmPgen	HarmPmax	DecrImpt	IncrImpt	AvrDFct	N_Help	HelpPgen	HelpPmax	DecrImpt	IncrImpt	AvrDFct
A	48	4981	5429	-899	81	0.1804	0	0	0	0	0	0
B	16	739	1016	-134	50	0.1812	0	0	0	0	0	0
C	53	5011	6811	-914	329	0.1824	0	0	0	0	0	0
D	28	1156	1494	-213	62	0.1840	0	0	0	0	0	0
E	98	481	943	-88	85	0.1834	0	0	0	0	0	0
F	69	2986	3993	-634	256	0.2230	0	0	0	0	0	0
G	7	15	53	-1	3	0.0631	19	3002	3442	204	-32	-0.0685
H	0	0	0	0	0	0	5	2027	2215	199	-18	-0.0978
I	0	0	0	0	0	0	1	3	3	0	0	-0.1071
J	0	0	0	0	0	0	80	7493	9531	803	-219	-0.1072
K	0	0	0	0	0	0	58	4183	5516	449	-143	-0.1072

Bus #	Bus Name	Zone	Pgen	Pmax	DistFct	ImpctUp	ImpctDn	ImpcTot	
319	Total Harm		15368	19738	0.1898	865	-2882	3747	
163	Total Helprs		16708	20707	-0.0998	-411	1655	2066	
257	TotHarLowImp		3045	4289	0.1773	221	-539	760	
131	TotHelpLowIm		5402	7375	-0.1008	-203	541	-743	
77950	9M PT 2G	C	1212	1212	0.1830	0	-222	222	==== Harmers ==
79547	JAFITZ1G	D	849	896	0.1830	9	-155	164	
77952	OSWGO 5G	C	0	881	0.1827	161	0	161	
77953	OSWGO 6G	C	312	881	0.1827	104	-57	161	
75523	KINTIG24	A	597	709	0.1810	20	-108	128	
77951	9M PT 1G	C	617	626	0.1830	2	-113	115	
79940	GINNA 19	B	509	525	0.1814	3	-92	95	
78708	ATHENSC2	E	217	217	0.3076	0	-67	67	
78710	ATHENSC3	E	0	217	0.3076	67	0	67	
78706	ATHENSC1	E	217	217	0.3076	0	-67	67	
79527	GILBOA#1	E	250	265	0.2403	4	-60	64	
79529	GILBOA#3	E	210	264	0.2403	13	-51	63	
79528	GILBOA#2	E	0	264	0.2403	63	0	63	
79530	GILBOA#4	E	0	262	0.2403	63	0	63	
78964	BETH STM	E	298	325	0.1888	5	-56	61	
77052	HUNT115G	A	320	340	0.1803	4	-58	61	
84278	BHN23 24	D	46	246	0.1840	37	-9	45	
77450	GERES LK	C	80	240	0.1819	29	-15	44	
79511	NIAG. 12	A	215	215	0.1806	0	-39	39	
79510	NIAG. 11	A	215	215	0.1806	0	-39	39	
79512	NIAG. 13	A	215	215	0.1806	0	-39	39	
79509	NIAG. 10	A	215	215	0.1806	0	-39	39	
79502	NIAG. 3	A	215	215	0.1805	0	-39	39	
79501	NIAG. 2	A	215	215	0.1805	0	-39	39	
79503	NIAG. 4	A	215	215	0.1804	0	-39	39	
79505	NIAG. 6	A	215	215	0.1804	0	-39	39	
79507	NIAG. 8	A	175	200	0.1806	5	-32	36	
76640	DUNKGEN3	A	180	197	0.1795	3	-32	35	
77050	HNTLY67G	A	185	191	0.1803	1	-33	35	
77051	HNTLY68G	A	180	191	0.1803	2	-33	34	

Glossary

AvrDFct	Average distribution factor
Bus #	Bus number from the power flow case
Bus Name	Bus name for the power flow case
DecrImpt	Decremental impact on monitored pair for redispatching to zero
DistFct	Distribution factor
Flow	MW flow from power flow case
HarmPgen	Power Flow Generation Dispatch, Harmers
HarmPmax	Power Flow Maximum Generation Dispatch, Harmers
HeadRm	Headroom, rating minus flow
HelpPgen	Power Flow Generation Dispatch, Helpers
HelpPmax	Power Flow Maximum Generation Dispatch, Helpers
ImpctDn	Incremental impact on monitored pair for redispatching to maximum
ImpcTot	Total impact
ImpctUp	Decremental impact on monitored pair for redispatching to zero
IncrImpt	Incremental impact on monitored pair for redispatching to maximum
Limit	MW limit from power flow case
Load%	Flow as % of rating
N_Harm	Number of Harmers
N_Help	Number of Helpers
Pgen	Power Flow Generation Dispatch
Pmax	Power Flow Maximum Generation Dispatch
Total Harm	Total Harmers
Total Helprs	Total Helpers
TotHarLowImp	Total low impact Harmers (below distribution factor cutoff)
TotHelpLowIm	Total low impact Helpers (below distribution factor cutoff)
Zone	Zonal location in the power flow case

Table C-2

Bus #	Bus Name	Zone	Pgen	Pmax	DistFct	ImpctUp	ImpctDn	ImpcTot	
76641	DUNKGEN4	A	185	191	0.1795	1	-33	34	
77970	SITH-S6	C	180	186	0.1830	1	-33	34	
77969	SITH-S5	C	180	186	0.1830	1	-33	34	
79508	NIAG. 9	A	175	175	0.1806	0	-32	32	
79504	NIAG. 5	A	175	175	0.1804	0	-32	32	
79506	NIAG. 7	A	175	175	0.1804	0	-32	32	
76642	DUNK115G	A	170	170	0.1795	0	-31	31	
76111	MILKN 2	C	156	165	0.1796	2	-28	30	
78711	ATHENSS3	E	0	96	0.3076	29	0	29	
78707	ATHENSS1	E	96	96	0.3076	0	-29	29	
78709	ATHENSS2	E	96	96	0.3076	0	-29	29	
76112	MILKN 1	C	156	161	0.1796	1	-28	29	
78952	JMC2ST13	E	148	148	0.1896	0	-28	28	
78963	BETHGT3	E	155	155	0.1724	0	-27	27	
78962	BETHGT2	E	155	155	0.1724	0	-27	27	
78961	BETHGT1	E	155	155	0.1723	0	-27	27	
77966	SITH-G2	C	135	143	0.1830	2	-25	26	
77967	SITH-G3	C	135	143	0.1830	2	-25	26	
77968	SITH-G4	C	135	143	0.1830	2	-25	26	
77965	SITH-G1	C	135	143	0.1830	2	-25	26	
79289	INDECK-C	E	149	153	0.1603	1	-24	25	
75964	GRNIDG 4	C	110	110	0.1791	0	-20	20	
79513	MOS17-18	D	54	107	0.1840	10	-10	20	
79515	MOS19-20	D	107	107	0.1840	0	-20	20	
79520	MOS23-24	D	107	107	0.1840	0	-20	20	
79516	MOS21-22	D	107	107	0.1840	0	-20	20	
79518	MOS25-26	D	107	107	0.1840	0	-20	20	
79521	MOS27-28	D	107	107	0.1840	0	-20	20	
79524	MOS31-32	D	107	107	0.1840	0	-20	20	
79522	MOS29-30	D	107	107	0.1840	0	-20	20	
78951	JMCGT13	E	95	95	0.1896	0	-18	18	
78953	JMCGT213	E	95	95	0.1896	0	-18	18	
79548	IP#3 GEN	H	1042	1080	-0.1031	-4	108	111	==== Helpers ==
74702	RAV 3	J	966	981	-0.1072	-2	104	105	
74701	IND PT 2	H	928	1078	-0.0923	-14	86	100	
79546	POLETTI	J	825	855	-0.1072	-3	89	92	
74700	AK 3	J	285	491	-0.1072	-22	31	53	
79390	BOW2	G	592	592	-0.0885	0	52	52	
79391	BOW1	G	350	592	-0.0884	-21	31	52	
74707	RAV 1	J	370	393	-0.1072	-3	40	42	
74909	NRTPTG4	K	358	393	-0.1072	-4	38	42	
74708	RAV 2	J	370	391	-0.1072	-2	40	42	
74907	NRTPTG2	K	358	389	-0.1072	-3	38	42	
74906	NRTPTG1	K	358	383	-0.1072	-3	38	41	
74908	NRTPTG3	K	358	381	-0.1072	-3	38	41	
74705	AST 4	J	361	371	-0.1072	-1	39	40	
74706	AST 5	J	361	367	-0.1072	-1	39	39	
74704	AST 3	J	330	353	-0.1072	-3	35	38	
74703	AK 2	J	300	352	-0.1072	-6	32	38	
75078	SHMHVDCL	K	330	330	-0.1072	0	35	35	
74190	ROSE GN1	G	599	610	-0.0550	-1	33	34	
74192	ROSE GN2	G	585	610	-0.0550	-1	32	34	
74919	HOLTS1-5	K	15	280	-0.1072	-28	2	30	
74918	HOLT6-10	K	99	280	-0.1072	-20	11	30	
74901	BARETG2	K	176	196	-0.1072	-2	19	21	
74913	PTJEFG4	K	171	195	-0.1072	-3	18	21	
74912	PTJEFG3	K	159	192	-0.1072	-4	17	21	

Table C-2

Bus #	Bus Name	Zone	Pgen	Pmax	DistFct	ImpctUp	ImpctDn	ImpcTot
74900	BARETG1	K	175	192	-0.1072	-2	19	21
74429	AST 2	J	175	175	-0.1072	0	19	19
79539	POLETSTG	J	0	170	-0.1072	-18	0	18
74302	ER G7	J	166	166	-0.1072	0	18	18
79540	POLETGT1	J	0	165	-0.1072	-18	0	18
79538	POLETGT2	J	0	165	-0.1072	-18	0	18
74917	BRTG9-12	K	144	164	-0.1072	-2	15	18