
Available Transfer Capability (ATC) Methodology Power Flow Base Case, Version 5

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This document describes the Power Flow Model and Base Case Assumptions used for calculation of Available Transfer Capability (ATC).

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1 Power Flow Model

- 1.1 The power flow model is a mathematical representation of the actual lines, transformers, loads, and generators that comprise the Columbia River Power system. A key output of this model is a computation of how much power will flow over each element in the power system for the assumed load and generation levels.
- 1.2 For the planning ATC calculations, power flows representing projected system conditions in each calendar year were modeled. Subsequent analysis will use base cases that reflect new or changed system conditions, particularly the addition of major new transmission facilities.
- 1.3 Northwest generation levels and load were limited to Firm commitments on the Bonneville transmission system to the extent possible. Since this creates a discrepancy between total Northwest generation and load, Intertie flows were adjusted accordingly.
- 1.4 The power flows over Network Flowgates were identified.
- 1.5 The difference between the power flow and the Total Transfer Capability (TTC) becomes the Planning ATC for the Flowgate. One Planning ATC is established per Flowgate, per season.

2 Power Flow Base Case Assumptions

- 2.1 Representative seasonal power flow cases were developed.
- 2.2 Normal peak (1 in 2 year) load forecasts were used for all seasons.
 - 2.2.1 Load forecasts for utilities that perform their own forecasts were obtained from such utilities as part of the Transmission Services' standard process for base case development.
 - 2.2.2 Load forecasts for utilities that do not do their own load forecasts were based on forecasts developed by Transmission Services.
- 2.3 Federal generation levels were set using a multiple step process. The Columbia Generating Station (formerly known as WNP-2) was assumed to be on-line at full load in the power flow cases in all seasons (in the Contract Accounting Methodology, however the plant was assumed to be off-line for maintenance during the months of April and May in the odd-numbered years). The portion of the plant's output that was not covered under federal Point to Point (PTP) contract demand was deemed to serve all contracts that call out non-specific federal projects as Points of Receipt (PORs).

2.4 Generation levels at each of the federal hydro projects¹ were set by first determining each project's 90th percentile generation value by month for the period 1997 - 2002. The 90th percentile value means each such project was at or below these generation levels 90% of the time during the given month. Generation levels at the Libby, Hungry Horse, Dworshak, and Albeni Falls projects, however, were set based on the requirements set forth in the 2000 Biological Opinion. In addition, the generation levels at the Willamette Valley projects were set at the minimum levels seen by season during Calendar Year 2001 as shown below:

Willamette Valley Projects 2001 Generation Seasonal Averages²

	Winter	Spring	Summer	Fall
Big Cliff	8	15	3	3
Cougar	8	14	11	14
Detriot	40	44	48	41
Dexter	4	10	0	0
Foster	7	12	4	7
Green Peter	28	24	23	23
Hills Creek	8	8	10	7
Lookout Point	35	45	38	23
Lost Creek ³	15	24	21	10
Sum	153	196	158	118

¹ Federal hydro projects include: Grand Coulee, Chief Joseph, Dworshak, Albeni Falls, Libby, Hungry Horse, Lower Granite, Lower Monumental, Little Goose, Ice Harbor, McNary, John Day, The Dalles, Bonneville, Willamette Valley Projects.

² Calendar Year 2001 was used because its averages were the lowest of the last 6 years. Winter: December - March; Spring: April - May; Summer: June - September; Fall: October - November.

³ Most recent data for Lost Creek is 1996. Data between 1996 and 2001 for Hills Creek and Lookout Point followed a pattern that was applied to Lost Creek's 1996 data to arrive at numbers used here. Hills Creek and Lookout Point were used as models due to their regional proximity to Lost Creek.

- 2.5 The generation at the federal hydro projects was then scaled to match the sum of the demands for all contracts that call out non-specific federal hydroelectric projects as PORs after adjusting these demands for the portion served by Columbia Generating Station, Libby, Hungry Horse, Dworshak, Albeni Falls, and the Willamette Valley projects. The federal PTP demands at each project were then added to this result to obtain the final assumed generation level for each federal hydro project. This overall method for modeling the federal resources is referred to as the "Modified 90th Percentile Method" and is used in both the power flow base cases and Contract Accounting Methodology.
- 2.6 Generation levels at the non-federal Mid-Columbia hydro projects were set at 90% of their historical output by season.
- 2.7 Non-federal thermal generators requiring transmission service on the federal transmission system were set at either their contract demand or seasonal capability, whichever was lower.
- 2.8 Wind generators identified as PORs in PTP contracts and that require transmission service on the federal transmission system were modeled on at 80% of the wind generator's contract demand.
- 2.9 The Flowgate impact of wind generators identified as Designated Network Resources in NT contracts or in the NT Resources ¹Memorandum of Agreement and that require transmission service on the federal transmission system are determined on a Flowgate by Flowgate basis, and set at the greater of the following:
 - 2.9.1 Modeled on at 100% of the designated MW level for the wind generator or
 - 2.9.2 Modeled off and replaced, at 100% of the designated MW level for the wind generator, by "Modified 90th Percentile Method" federal generators.
- 2.10 Non-federal resources that do not require transmission service from Transmission Services were set at levels obtained from such resource owners as part of Transmission Services' standard process for power system planning studies.
- 2.11 A summary of power flow assumptions is posted on the ATC Methodology page of Transmission Services' web site.

3 Determining Planning ATC

- 3.1 The power flow base cases for each season were run using the assumptions described in Section 2. The resulting flows across each Network Flowgate ("Planning Power Flow") were obtained and compared to each Flowgate's TTC. The difference between the Flowgate TTC and the Planning Power Flow is the "Planning ATC".
- 3.2 Transmission Services reserves the right to modify the Planning ATC at any time.

¹ Memorandum of Agreement, Management of Federal Power Sales for Network Integration Transmission Service, MOA No. 02TX-10925.

4 Parallel Flows

4.1 The Network Flowgates do not necessarily represent all transmission lines across that particular constrained portion of the power system. In the Planning power flow studies for determining Planning ATC and TTC for the Network Flowgates, Transmission Services accounts for power flow across Transmission Services' facilities only. The flows on all facilities for several constraints follow. The information contained in the following chart is not intended to establish a formal allocation between Transmission Services and other transmission owners.

Constraint	Case				
	MAY04M3 (MW)	JUN04M3 (MW)	A04M3 (MW)	JO4M3 (MW)	JO4EHM3 (MW)
From Substation- To Substation Voltage					
West of McNary	2598	2511	2310	1852	1788
<u>Coyote Springs-Slatt</u> 500kV	1801	1733	1578	1145	971
<u>McNary-Ross</u> 345kV	295	284	260	380	450
<u>McNary-Horse Heaven</u> 230kV	313	314	296	160	193
<u>McNary-Boardman Tap</u> 230kV	189	181	176	168	174
South of Allston	2479	2504	2478	766	208
<u>Allston-Keeler</u> 500kV	1369	1401	1420	122	-239
<u>Lexington-Ross</u> 230kV	292	257	250	165	91
<u>Allston-St. Helens</u> 115kV	75	78	76	42	35
<u>Astoria-Seaside</u> 115kV	-12	-8	-7	-27	-36
<u>Trojan-St. Mary's</u> 230kV	286	292	287	129	77
<u>Trojan-Rivergate</u> 230kV	229	240	236	83	59
<u>Merwin- St. Johns</u> 115kV	151	159	128	150	111
<u>Clatsop-Lewis & Clark</u> 115kV	89	85	88	102	110

South of Napavine	1889	1908	1996	550	600
<u>Napavine</u> -Allston #1 500kV	973	982	1025	325	349
<u>Paul</u> -Allston #2 500kV	916	926	971	225	251

Notes: (a) The "from" and "to" substations are listed in the direction of positive flow; (b) the underlined substation is where the flow is metered; and (c) numbers are rounded.

5 Revision History

6/17/08, V5	This version update reflects a proposal to no longer use a 1-in-20 load forecast in the winter Power Flow Base Cases for the Cross-Cascades Flowgates, and corrects a typo. As a result of Customer comments received, Step 2.9 was modified.
5/14/08, V4	Incorporated modifications to the manner in which designations of wind generators as Network Resources are modeled.
04/14/05, V3	Reformatted document per current business practice standards.
02/11/04, V2	New Power Flow Base Case and assumptions based on 2006 infrastructure.
11/12/03, V1	This document was included as Appendix 6 of the ATC Methodology.