Table I: Step-By-Step Calculation of Extraction Turbine Comparison

DERIVATION OF EXTRACTION FLOWS AND THROTTLE FLOWS

			400 psig – 750F		600 psig – 825F		850 psig – 900F		400 psig
1		Initial pressure and temperature							
		NONCONDENSING EXTRACTION TURBINE							
2	Select	Output, kw	7,500	7,500	7,500	7,500	7,500	7,500	7,500
3	A1 (3) & (4)	Throttle flow, lb per hr	235,700	255,700	153,600	210,000	160,300	182,300	764,300
4		Extraction flow, for process and feedwater heating, lb per hr	120,000	160,000	120,000	160,000	120,000	160,000	120,000
5	(3)–(4)	Exhaust flow, for process and feedwater heating, lb per hr	115,700	95,700	33,600	50,000	40,300	22,300	141,300
6	Fig. 1 or (3)	Enthalpy of steam at extraction opening, Btu per lb	1388.6	1389.3	1388.6	1387.6	1310.1	1310.0	1221.2
7		Enthalpy of liquid at extraction pressure, Btu per lb	338.3	338.3	338.3	338.3	338.3	338.5	338.3
8	(5)–(7)	Heat in process and feedwater above (7), Btu per lb	970.3	971.0	970.3	969.3	971.8	971.5	882.9
9	(4)x(8)	Heat in process and feedwater above (7), Btu per hr	116.4×10^6	155.3×10^6	116.4×10^6	155.1×10^6	116.7×10^6	155.5×10^6	105.9x10⁶
10	Fig. 6a(5)	Enthalpy drop from extraction opening to exhaust, Btu per lb	65.9	66.1	64.5	51.3	56.5	31.2	66.1
11	(6)–(10)	Enthalpy of steam at exhaust opening, Btu per lb	1256.1	1143.2	1244.1	1754.1	1253.6	1278.8	1155.1
12		Enthalpy of liquid at exhaust pressure, Btu per lb	267.3	267.3	267.3	267.3	267.3	267.3	267.3
13	(11)–(12)	Heat in process and feedwater above (12), Btu per lb	971.0	975.8	976.8	986.8	986.3	1011.5	867.8
14	(9)x(13)	Heat in process and feedwater above (12), Btu per hr	113.9×10^6	93.6×10^6	71.9×10^6	49.3×10^6	47.65×10^6	22.75×10^6	83.6x10⁶
		CONDENSING EXTRACTION TURBINE							
15	(A)–(7)	Output, kw	7,500	7,500	7,500	7,500	7,500	7,500	7,500
16	A1 (15) & (17)	Throttle flow, lb per hr	110,700	134,600	117,400	134,300	104,950	115,150	109,270
17		Extraction flow, lb per hr	60,000	100,000	69,000	120,000	80,000	100,000	65,000
18	(15)–(17)	Condenser flow, lb per hr	50,700	34,600	32,400	14,300	24,950	15,150	44,270
19	Fig. 11 a (16)	Enthalpy of steam at extraction opening, Btu per lb	1248.2	1241.6	1239.3	1235.2	1239.7	1237.0	1195.1
20	(12)	Enthalpy of liquid at extraction pressure, Btu per lb	267.3	267.3	267.3	267.3	267.3	267.3	267.3
21	(19)–(20)	Heat in process and feedwater above (12), Btu per lb	980.9	974.3	972.0	967.9	972.4	969.7	927.8
22	(17)x(21)	Heat in process and feedwater above (12), Btu per hr	58.854×10^6	97.43×10^6	71.5×10^6	116.1×10^6	77.8×10^6	96.97×10^6	82.1x10⁶
		CALCULATION OF ANNUAL FUEL COST AND FUEL SAVING							
		NONCONDENSING EXTRACTION TURBINE							
23	(2)	Output, kw	7,500		7,500		7,500		7,500
24	(B,1)	Heat to 150 psig extraction line above (7), Btu per hr	129.6×10^6		129.6×10^6		129.6×10^6		129.6x10⁶
25	Fig. 12 a(24)	Heat to 50 psig exhaust line above (12), Btu per hr	101.7×10^6		84.5×10^6		99.2×10^6		119.8x10⁶
26	Fig. 12 a(24)	Throttle flow, lb per hr	241,600		198,200		172,720		173,200
27	Fig. 12 a(24)	Extraction flow, lb per hr	132,500		132,500		112,200		112,200
28	(26)–(27)	Exhaust flow, lb per hr	109,100		65,700		60,520		60,800
		CONDENSING EXTRACTION TURBINE							
29	(15)	Output, kw	7,500		7,500		7,500		7,500
30	(B,2)–(22)	Heat to 50 psig extraction line above (12), Btu per hr	76.7×10^6		117.3×10^6		142.2×10^6		58.4x10⁶
31		Heat to 50 psig line from turbine, Btu per hr	76.7×10^6		117.3×10^6		112.7×10^6		58.4x10⁶
32		Heat to 50 psig line from reducing valve, Btu per hr	0		0		29.5×10^6		0
33		Throttle flow, lb per hr	121,100		135,800		123,560		121,000
34		Extraction flow, lb per hr	77,900		121,300		115,900		63,000
35	(33)–(34)	Condenser flow, lb per hr	43,200		13,700		7,600		58,000
36		Steam passing through reducing valve, lb per hr	0		0		29,100		0
37	A1 (1)	Initial enthalpy, Btu per lb	1388.9		1478.9		1455.1		1388.7
38	(7)–10	Enthalpy of feedwater to boiler, Btu per lb	328.3		328.3		328.3		328.3
39	(37)–(38)	Heat added to boiler, Btu per lb	1060.6		1092.6		1126.8		1060.4
40	(29)+(33)+(36)	Total steam flow from boiler, lb per hr	362,900		337,800		337,300		362,300
41	(39)x(40)	Total heat added to boiler, Btu per hr	384.9×10^6		364.7×10^6		362.5×10^6		384.2x10⁶
42	Assume	Boiler efficiency, fraction	.85		.85		.85		.85
43	Assume	Auxiliary efficiency, fraction	.96		.953		.95		.96
44	$\frac{(41)}{(42)(43)}$	Fuel supplied to boiler, Btu per hr	471.7×10^6		449.3×10^6		448.9×10^6		471.9x10⁶
45	Assume	Hours of operation per year	7,500		7,500		7,500		7,500
46	Assume	Cost of oil, dollars per gal	2.10		2.10		2.10		2.10
47	Assume	Heat content of oil, Btu per gal	140,000		144,000		144,000		140,000
48	$\frac{(44)(45)(46)}{(47)(2)}$	Annual fuel cost, dollars	1,770,400		1,778,100		1,769,000		1,854,900
49		Annual fuel saving, dollars	78,500		84,900		85,900		0

EXTRACTION TURBINES *continued*

polated for use in the second section of this table.

The noncondensing steam turbine is the only heat source to the 150-psig line. With the 7500-kw load under consideration, an inspection of the flow curves in Fig. 1 to 4 indicates the approximate extraction flow needed to supply the 150-psig heat demand. In other words, at 7500 kw the extraction flow should be somewhere between 120,000 and 160,000 lb per hr. With these flows, data are worked out on lines 4 to 14. These data are plotted on Fig. 12 with the heat to 150-psig line as the abscissa because this is supplied only by the noncondensing steam turbine.

At the 150-psig heat requirement from Table II, heat supplied to the 50-psig line at each initial steam condition is *indicated*. Subtract this heat from the total required as given in Table II, line B-2; the condensing turbine must supply the remainder. Extraction flow corresponding to this heat is estimated, and bracketing extraction flows can be selected for use with Fig. 7 to 10 in calculating lines 16, 17 and 18. This table indicates the *remaining* operations up to line 22. Data from these calculations are plotted on Fig. 13 against heat to 50-psig line.

We are now ready to make the calculations for *Annual fuel cost*. As before consider the noncondensing extraction turbine first. At 7500-kw load enter Fig. 12 at the total heat required at 150-psig line, and read items for lines 25 to 27. Line 25 is the quantity of heat

Table II: General Data and Process Requirements

A. Total load 15,000 kw

B. Process and feedwater heating requirements:
1. High-pressure line: 150,000 lb per hr of 150-psig saturated steam, usable heat = 128.6×10^6 Btu per hr
2. Low-pressure line: 200,000 lb per hr of 50-psig saturated steam, usable heat = 182.4×10^6 Btu per hr

C. Noncondensing 7500-kw turbine with automatic extraction at 150 psig and exhaust at 50 psig

D. Condensing 7500-kw turbine with automatic extraction at 50 psig and exhaust at 2 in. Hg abs

E. Alternate steam conditions selected at top of selling-price brackets

...ntical to the 50-psig line by the ex-...st of the noncondensing turbine. ...Remainder of heat needed by the ...50-psig process line must come from ...the condensing extraction turbine ...through a pressure-reducing desuper-...heating station. For the 400- and 600-...psig turbines, this heat is supplied by ...extraction from these units. A quick ...test of this would be to proceed down ...line 35; if this equals or exceeds min-...imum flow to condenser, the turbines are ...supplying this steam. For the 850-psig ...turbine, you find the flow to exhaust is ...negative when extracting the full bal-...ance to the 50-psig line.

Data for lines 33, 34 and 35 are obtained as follows:

For 400 psig, 600 F; 400 psig, 750 F; 600 psig, 825 F: Enter Fig. 13 at the heat to 50-psig line from the turbine (line 31), and read throttle flow (line 33) and extraction flow (line 34). Condenser flow (line 35) is the difference between these quantities.

For 850 psig, 900 F: Enter Fig. 13 at the minimum flow to exhaust on the condenser flow line for these steam conditions. Read the corresponding heat to 50-psig line, throttle flow and extraction flow.

Now find the heat to 50-psig process line from the reducing station (line 32), and calculate the required steam flow, as follows:

$$\left[1+\frac{h_a-h_f}{h_f-q_o}\right](h_f-q_f)=\Delta Q$$

For given steam conditions and desuperheater spray-water temperature, this reduces to:

X = ΔQ/constant

ΔQ = heat in desuperheated steam above (12), Btu per hr

X = steam flow to reducing valve, lb per hr

h_a = initial enthalpy of steam, Btu per lb

h_f = final enthalpy of desuperheated steam, Btu per lb

q_f = enthalpy of liquid at 50 psig, Btu per lb

q_o = enthalpy of spray water, Btu per lb

Assuming desuperheated steam to be saturated at 50-psig and 200-F spray water:

$X = \Delta Q/1159 = 30.3\times10^6/1159$

$= 26{,}100$ lb per hr

Heat to process at each line has been assumed to include steam for feedwater heating. Therefore, the final enthalpy of feedwater has been taken as 10 Btu less than the enthalpy of saturated liquid at 150 psig on the assumption that a closed feedwater heater will be used at this point.

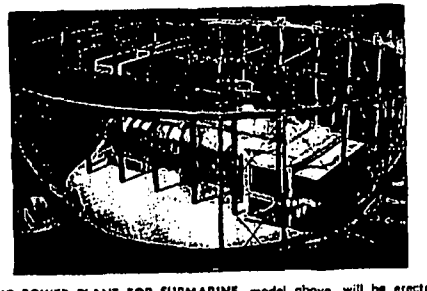
Reasonable values of boiler efficiency have been assumed. A variation of auxiliary efficiency has been made to approximate the change in auxiliary losses due to change in boiler-feed-pump power with boiler pressure.

Operating hours per year, fuel cost, and fuel heat content have been taken from an actual problem. *These items* would change for any specific application. If other loads and operating hours are to be included in a study, the complete group of steps, starting at line 1, should be repeated. In the end, annual fuel cost at each load should be summed up for the total annual fuel cost.

Line 27 of Table I, extraction flow, under the 400-psig 600-F and 400-psig 750-F conditions shows the different extraction flows, 143,200 and 132,500 lb per hr, required to supply the same heat to 150-psig process because of difference in enthalpy at the extraction opening. If evaluations are made on a constant-steam-flow-to-process basis without regard to enthalpy, the condition with the higher enthalpy is penalized. This method properly credits each alternative with its enthalpy at extraction point.

Line 49, annual fuel saving relative to the 400-psig 600-F application indicates only a small gain between 600 psig and 850 psig at the conditions of *this study*. The 850-psig initial pressure would not appear to be economical. Investigation at other loads and process needs, however, may show the higher pressure and temperature as worthwhile. Condenser flow, line 35, is a criterion on the minimum fuel cost, provided there is no steam passed through the reducing valve.

Future loads and process needs may indicate that the higher-temperature turbine, over a period of years, may be more flexible and economical than the lower-pressure alternative.



ATOMIC POWER PLANT FOR SUBMARINE, model above, will be erected in 225-ft-dia steel sphere by G E Co. Water surrounds part of hull section