CHES, Casing Hydraulic Expert System

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ABSTRACT

An operations-oriented, practical application of expert systems technology to tubular design and optimizing bit hydraulics has been developed and is called CHES (Casing Hydraulic Expert System).[1] Drilling operations are the most costly expenditure in the process of exploiting hydrocarbon fossil fuels. Drilling costs during 1981 to 1991 have each year exceeded one-third to one-half the total capital and exploration outlays for U.S. domestic projects. The reduction of drilling cost is more important than ever in the oil industry today.

An important way to decrease drilling costs is to increase the penetration rate of the bit. Optimizing bit hydraulics is an important task facing drilling engineers in order to increase drilling rate. Rheology, hydraulics, and bit nozzle selection are parameters to be considered when optimizing drilling.

CHES is written using an expert system shell (LEVEL-5, from Information Builders, Inc.). The backward chaining rule base interfaces with DB3 (Data Base 3), numerous FORTRAN programs, and chains from one knowledge base to another. CHES was developed and implemented on an IBM PC AT microcomputer.

INTRODUCTION

An operations-oriented, practical application of expert systems technology to tubular design and optimizing bit hydraulics has been developed and is called CHES (Casing Hydraulic Expert System). The expert system plans both the casing and hydraulics programs of a drilling well. In general, computing for drilling engineering has lagged behind that for production engineering, reservoir engineering, formation evaluation and reservoir geology, and exploration. This is unfortunate because the drilling operations have been by far the most costly expenditure in the process of exploiting hydrocarbon fossil fuels. Drilling costs during 1981 to 1991 have each year exceeded one-third to one-half the total capital and exploration outlays for U.S. domestic projects.[2] The reduction of drilling cost is more important than ever in the oil industry today.

Certain problems in the petroleum industry are being analyzed by a relatively new aspect of computer systems known as artificial intelligence (AI). Expert systems, the more commonly used name for knowledge engineering applications of artificial intelligence, are created by capturing knowledge and experience from experts in any given technical field as a series of rules. A computer applies data (in conjunction with the more familiar and conventional numerical models) to these rules which results in decisions being made in the same manner as human experts dealing with the problem.

The function of an expert system is to serve as a consultant, designer, monitor, problem solver, and/or tutor. Other industries have rapidly expanded the use of expert systems to solve problems, improve efficiencies, capture knowledge as a resource, and train inexperienced personnel. Only recently has the drilling industry become a leading application area for expert systems. A number of factors contribute to this situation:

1) Investments are substantial and failures will have consequences far surpassing those in most other industries, both in terms of economic loss and human life.
2) Drilling problems in harsh environments have become increasingly complex, requiring a multitude of scarce experts to work interactively and combine their expertise.
3) Volume of information is increasing dramatically with advances in data and sensor technology requiring new and more efficient ways to handle information in an "intelligent" manner.
4) Many critical decisions, such as emergency procedures, must be made quickly with great precision during crises such as blow-outs and fires.

Expert systems are nothing more than programs. There are four basic characteristics that make them different from most conventional programs:

1) An expert system has "knowledge" in a narrow domain or field of expertise.
2) It utilizes symbolic reasoning.
3) The system has depth of knowledge.
4) An expert system can "explain" its behavior.

An important way to decrease drilling costs is to increase the penetration rate of the bit. The less time spent drilling the hole, the fewer problems that are incurred. Most hole problems develop slowly and become serious considerations only after enough time has passed. Optimizing bit hydraulics is an important task facing drilling engineers in order to increase drilling rate. Rheology, hydraulics, and bit nozzle selection are parameters to consider when optimizing drilling.

CHES, a knowledge base for designing casing strings and optimizing bit hydraulics, is written with an expert system shell called LEVEL-5, from Information Builders, Inc. This shell was chosen for the following reasons:

1) It interfaces with commercial software programs. A database tool, DB3, was used to store the tubular parameters, for example; inventory, price, dimensions, and strengths.
2) It can activate programs written in several common computer languages. FORTRAN subroutines were written to perform the numerous iterative calculations.
3) It is implemented in the C language, which allows it to run faster than many AI tools that use LISP or PROLOG type languages. This makes it feasible to develop large applications that can operate on microcomputers.
4) It can run on diverse hardware. The knowledge base was developed and debugged on an IBM PC AT.
5) The problems could be adapted to take advantage of the tool's backward chaining inference engine.
6) It is a reliable expert shell that is well supported and has been used for other applications in the department of Petroleum Engineering.
7) It can chain from one knowledge base to another. This allowed each module to be developed and tested independent of the others. Changes in one module will not cause another to give unexpected results.
8) It was a relatively inexpensive tool and having been purchased by the Petroleum Engineering department was readily available.

STEPS IN HYDRAULIC DESIGN

A. INTRODUCTION

There are many interrelated steps in the hydraulic design process:

1) Obtain rig pump information and determine the limitations it places on the hydraulic plan; maximum flow rate at maximum pressure.

2) Determine the wellbore geometry; the lengths and diameters of the conduits in the circulation system.

3) The fluid rheology must be known or determined from viscometer measurements in order to calculate the pressure losses using the best fluid model.

4) Calculate the minimum annular velocity to lift cuttings and the minimum flow rate for this velocity.

5) Calculate the maximum annular velocity that still allows laminar flow and the maximum flow rate for this velocity.

6) Compare the maximum flow rates from steps 1 and 5, select the lowest and ensure that flow rate is higher than the minimum flow rate from step 4.

7) Calculate the parasitic pressure losses at both the maximum and minimum flow rates.

8) Determine the slope of the log-log relationship between the parasitic pressure loss and flow rate.

9) Calculate the flow rate at the optimum parasitic pressure loss, using the information in step 8.

10) Calculate the nozzles sizes that will give the required pressure drop across the bit.

B. MUD PUMP INFORMATION

Since the rig mud pump is the source of hydraulic energy in the circulation system, it is important to know the constraints on these pumps. The drilling engineer must consider these in designing a well hydraulic plan. Pumps are rated for hydraulic power (P_{HP}), maximum pressure (p_{max}), maximum flow rate (q_{max}), and mechanical and volumetric efficiency (E_m and E_v). The hydraulic power output of the pump is equal to the discharge pressure times the flow rate. For a given hydraulic power level, the maximum discharge pressure and flow rate can be varied by changing the stroke rate and liner size. A smaller liner will allow the operator to obtain a higher pressure, but at a lower rate. Pressures above 3500 psig are normally not used on rig pumps due to high maintenance costs. Mechanical efficiency ranges are 85%-95%, and volumetric efficiency ranges are 95%-100%. Duplex efficiencies are in the lower ranges whereas triplex efficiencies are at the top ranges.

Rig pumps use reciprocating positive displacement pistons. These pumps are able to move high solids content fluids laden with abrasives, and to pump large particles, easy to operate and maintain, reliable, and operate over a wide range of pressures and flow rates. Two types of pumps are found on drilling rigs: two-cylinder (duplex) double-acting pumps and three-cylinder (triplex) single-acting pumps. Triplex are generally favored because they are lighter, more compact, cheaper to operate, and their output pressure pulsations are not as great. Most drilling rigs have two mud pumps. The drilling engineer selects the rig to use in drilling a well partially based on the capacity of the mud pumps. Once this selection has been made maximum limits can be placed on the hydraulic plans.

C. GEOMETRY OF WELLBORE

The wellbore geometry is a series of conduits that the drilling mud, mist, air, foam, or cement flows through from the pump discharge to the mud pits. These components of the circulation system consist of: 1) surface equipment, 2) drillpipe, 3) drill collars, 4) bit and bottom hole assembly, 5) annulus between drill collars and open hole, 6) annulus between drill collars and cased hole, 7) annulus between drill pipe and open hole, and 8) annulus between drill pipe and cased hole. When making hydraulic calculations, the drilling engineer is interested in the length and diameters (ID and OD) of these components and the flow pattern of the fluid (jet, turbulent or laminar) in each of these components. Some of these dimensions are established by the casing plan, the bit plan, the fluid rheology, and or equipment available in the drilling rig.

1. Surface Equipment. The surface equipment consists of four components: the standpipe, the drilling or rotary hose, the swivel washpipe and gooseneck, and the kelly. These components are forced into one of four combinations which are then treated as an equivalent length of drillpipe for the purposes of hydraulic calculations. Flow in the surface equipment is normally turbulent. Table I lists the four typical surface combinations and the their equivalent lengths of drill pipe.

2. Drillpipe. The major portion of the drillstring is composed of the drillpipe. The drillpipe is hot-rolled, pierced, seamless tubing with tool joints (pin and box) formed on the tube ends to connect the drillpipe joints. The tool joints have a thicker wall than the tube part of the drillpipe. This thicker portion of the pipe is called the upset. The upset is formed by decreasing the internal diameter or increasing the external diameter (or both) of the tube. A rounded-type thread is used and the external facing of tungsten carbide is often put on the tool joint. Range 2 (approximately 30 ft. long) drillpipe is most commonly used. The drill pipe length is the total measured depth of the hole less the drill collar length and the bit or bottom hole assembly length. The flow pattern in the drillpipe is turbulent. The inside diameters (ID) and outside diameters (OD) of drillpipe are specified by API. Table II lists some of the API specifications of typical drillpipe. Due to the thicker tool joint sections of drillpipe equivalent-ID and OD (which depend on tool joint type and Range 2 length) are used in hydraulic calculations. The OD of the drillpipe must be sized such that the annular cross-section between the drillpipe and the cased hole ID is small enough to allow for a flow velocity large enough to lift cuttings (q_{min}).

3. Drill collars. The lower section of the drillstring is composed of drill collars. The drill collars are thick-walled heavy steel tubulars used to apply weight to the bit and reduce the dogleg severity of the hole (stabilizer subs are also used to keep the drill collar string centralized) . The drillpipe is thin walled and would tend to buckle and soon fail if it was used for these purposes. The length of the drill collars is dependent upon the desired weight on bit and the density of the drilling mud. The diameters of typical API drill collars are listed in Table III. The flow regime is turbulent (the ID of the drill collars are smaller than the drillpipe). The OD of the drill collars must be sized such than the annular cross-section between the drill collars and the open hole (bit OD) is large enough to allow for laminar flow (q_{max}).

4. Bit and Bottomhole assembly. The flow pattern is based on jet nozzle flow and only depends on fluid rate and density, not on fluid rheology. Approximately 65% of the pump working pressure should be expended across the bit nozzles. Drilling bits have three

ports in which nozzles from 5/32 inch to 32/32 inch can be inserted. Nozzles sizes smaller than 5/32 inch tend to plug, and are avoided. This allows the total nozzle area (A_T) to be varied in order to approximate the desired pressure drop across the bit (Δp_B). Once this nozzle area has been determined a slight adjustment in flow rate, q is required in order to use all of the pump's working pressure. The nozzle sizes selected must be flexible enough to work at the depth the bit is entering the hole as well as at the depth it is projected to be removed from the hole after it is worn out.

Sutko, in experimental work using a physical model of a rock fragment, found that the force on a rock fragment beneath a bit is increased when unequal nozzle sizes are used.[3] However, most drilling engineers prefer to divide the flow as evenly as possible among the three nozzles to allow even bit cooling and bit cone cleaning.

5. Drill Collar Open Hole Annulus. This is the donut shaped cross-sectional area between the drill collar OD (d_1) and the open hole or bit OD (d_2). The length of this section is the shortest of either the drill collar length or the open hole length. (Shortly after drilling out from under casing the drill collars are longer than the open hole because some of the drill collars are still up inside the casing.) This annular cross-section is the smallest and therefore the annular velocity will be the highest. If this section is in a laminar flow pattern all the remaining annular cross-sections will also be in laminar flow. $Q_{max_{laminar}}$ is determined based on laminar flow in this annulus.

6. Drill Collar Cased Hole Annulus. This segment has a cross-section between the drill collar OD (d_1) and the casing ID (d_2). The length of this segment is either the drill collar length minus the open hole length, as long as there are drill collars still in the casing, or later it has a length of zero (after the open hole section is longer than the drill collar length). The desired flow pattern in this segment as in all the annular segments while drilling is laminar.

7. Drillpipe Open Hole Annulus. This annulus is between the drillpipe OD (d_1) and the bit OD or open hole (d_2). The length of this section is either zero (there are still some drill collars in the casing) or the open hole length minus the drill collar length.

8. Drillpipe Cased Hole Annulus. The last segment of the U tube is the annulus between the drillpipe OD (d_1) and the casing ID (d_2). The length of this section is shorter of either drillpipe length (some drill collars still in the casing) or the casing length. The velocity in this annulus is the slowest, but it must be fast enough to ensure cuttings are lifted out of the wellbore. The minimum flow rate, q_{min}, is determined at this annulus.

D. RHEOLOGY OF FLUID

Determining which fluid model, Newtonian, Bingham plastic, or Power-law, should be used in the laminar flow pressure drop calculations is based on several considerations. API recommends the Power-law model for drilling muds, the Bingham plastic model for cements, and the Newtonian model for water, brines, and oils. A better method of determining the correct model is one based on the available rheology data. If n and K parameters are given then the Power-law model is used. While if μ_p and τ_Y are available, then the Bingham plastic model is used. And if only μ is known then the Newtonian model is used. A preferred method is to start with actual viscometer data and using a least squares curve fit determine the best fit. A straight line fit of a linear plot of shear stress (τ) vs.

shear rate (γ) indicates a Bingham plastic model, while a straight line fit of a log-log plot indicates a Power-law model. Lastly the units of τ, γ, RPM, θ, μ, μ_p, τ_y, n, K, and ρ must be checked for compatibility.

E. FLOW RATE LIMITS

The flow rate that is acceptable is bounded by q_{min} and q_{max}. Once a flow rate is determined, it will remain constant throughout the entire circulation system. The flow pattern (jet, turbulent, or laminar) is dependent upon the fluid velocity in the conduit, and that velocity is a function of the fixed flow rate in the entire system and the cross-sectional area of the conduit.

$$v_{pipe} = q / (2.441 * d^2)$$

and

$$v_{annulus} = q / [2.441 * (d_2^2 - d_1^2)]$$

The minimum flow rate (q_{min}) is based on the minimum velocity required to lift cuttings in the annulus. The slowest velocity in the annulus will occur at the largest annular cross-section or at the annulus between the casing ID and the drillpipe OD. Several techniques are used by the drilling engineer to determine the minimum annular velocity. With a minimum annular fluid velocity equal to twice the cuttings settling velocity (v_{sl}), a cutting transport ratio (F_T) of 50% is obtained. Stoke's cuttings settling velocity correlation is used for Newtonian fluids. Moore's is used for Power-law fluids and Chein's is used for Bingham plastic fluids. Walker & Mayes' correlation is used for all three models. Sample and Bourgoyne, using all the available published experimental data on cuttings slip velocity in flowing fluids, compared the empirical correlations.[4] Their data consisted of measurements obtained for different fluid types (water, polymer, and clay muds) using a variety of particle types and sizes (spheres, disks, rectangular prisms, and actual rock cuttings). An average between the three non Newtonian correlations was closest to actual results. Walker & Mayes gave the slowest slip velocity and Chein the fastest slip velocity while Moore was slow but the most accurate. Considering the actual and empirical particle slip velocities methods and considering a cutting transport ratio of 50%, two rules of thumb can be stated for minimum annular velocities:

1) use v_{min} = 1 ft/sec for drilling mud and 2) use v_{min} = 2 ft/sec for Newtonian fluid.

The maximum flow rate is the lowest of two values: q_{max} laminar and q_{max} pump. The maximum flow rate above which turbulent flow occurs in the annulus (q_{max} laminar) is determined based on a maximum velocity in the smallest annular cross-section (between the open hole or bit OD and the drill collar OD). Since all other annular cross-sections will be larger, and their velocities smaller they will be in laminar flow if the smallest annular cross-section is in laminar flow. The maximum flow rate of the pump (q_{max} pump) at maximum pump working pressure (p_{max}) is based on pump horsepower.

Finally q_{max} must be greater than q_{min}; if this is not the case a change in wellbore geometry is necessary (either an increase in drillpipe OD or a decrease in drill collar OD).

F. DETERMINE BIT NOZZLE SIZES

The bit nozzle sizes are determined in order to have the maximum hydraulic horsepower (or impact force) expended across the bit. This maximum horsepower (or impact force) is bounded by three constraints:

1) The minimum flow rate in the annulus for proper cuttings transport, q_{min}, placed on the drilling operation by the deeper part of the hole, is used to find the parasitic pressure losses at various depths. The remaining pump pressure is the pressure drop available across the bit at these depths based on this constraint.

2) The maximum flow rate, q_{max}, placed on the drilling engineer by the shallow part of the hole, is used to find the parasitic pressure losses at various depths. The remaining pump pressure is the pressure drop available across the bit at these depths based on this constraint.

3) The intermediate hole corresponds to the optimum parasitic pressure drop based on the maximum bit hydraulic horsepower theory or maximum bit impact force theory, $\Delta P_{d_{opt}}$, is used to find q at various depths. The remaining pump pressure is the pressure drop available across the bit at these depths based on this constraint.

The ΔP_d's are calculated at constraints (1) and (2) at depths of interest. A straight line log-log fit between (1) and (2) at each depth is assumed. This fit is justified by (a) the Power-law model assumption; (b) since most of ΔP_d is turbulent flow (the Power-law, Newtonian, and Bingham plastic models all use Stanton's friction factor correlation chart to calculate turbulent ΔP), and (c) ΔP_d from q_{max} and q_{min} is over generally a short range (a calculation of ΔP_d at [$(q_{max} + q_{min})/ 2$] checks the straight line log-log fit).

This process, per Bourgoyne etal, is a log-log plot of flow rate, q, vs. parasitic pressure losses, ΔP_d. The shallow part of the hole corresponds to interval 1, a vertical line drawn through q_{max}. The intermediate hole corresponds to interval 2, a horizontal line drawn through $\Delta P_{d_{opt}}$. Interval 3 corresponds to the deeper hole, a vertical line drawn through q_{min}. The pressure drop at q_{min} and q_{max} at depths of interest are calculated and the slope, m, is determined.

Once the flow rate and parasitic pressure loss have been determined by iteration, the remaining pump pressure is expended at the bit. Based on equations from section IV.H, the total nozzle area is calculated. Three bit nozzles are selected from the available sizes which are as close as possible to the calculated total nozzle area. The actual pressure drop at the bit is determined and the flow rate is minimally adjusted so maximum pump working pressure is used.

DISCUSSION OF RESULTS

The expert system is adapted to design casing strings, determine the proper relationship between bit sizes and tubulars, and calculate the bit nozzle sizes by determining a fluid rheology model, flow pattern and frictional pressure drop in the circulation system. The validation of the various modules in the expert system was based on previously published data and hand calculations. Some of the expert system decisions are based on the author's personal biases concerning certain methodology, however, the author has considerable expertise in this area and has backed up his decisions with accepted drilling engineering human experts and statistical information. Each mathematical model was tested using published data and/or problems. Where possible several methods, starting from different points or approaches, were used to determine a potential answer and the results were assigned confidence factors to make the final decision.

Seventeen casing strings designed by manual calculations compare favorably to the expert system's results. Table IV lists the casing string cost by manual calculation and CHES's cost. As can be seen the average difference in cost is 0.13 %. This difference is partially due to the fact that the expert system is able to iterate to a closer tolerance than is reasonable manually.

The bit sizes and tubular diameters determined by the expert system are based on API casing connection outside diameters and recommended openhole casing OD cement clearances. The next smaller bit is based on its ability to pass through the drift diameter of the casing. CHES uses standard API casing and bit sizes.

One of the more difficult decisions the expert system makes is which rheology model best represents the fluid. Six sample fluids from published reports were used as data sets. Tables V and VI shows the values of μ_p, τ_y, n, and K calculated by CHES and the respective sources. CHES chose the Bingham's plastic model, using only γ (shear rate) data values greater than 100 (1/sec), in four cases (API 13D[5], HOWCO[6], DOWELL[7], and (cements are considered to follow the Bingham's model) while the API 13D and IADC/SPE were drilling muds. The IADC/SPE fluid was a very complicated mud that was modelled by Skalle in four rheology γ-ranges (1-24, 23-90, 65-100, 90-135). He found a Power-law fit for each of these ranges, but was unable to find a good average fit. API only calculated Power-law, n and K values for it's fluid (this was an example Power-law calculation). The other two example fluids, (API 10 pg. 82 and pg. 87[8]), were found to follow the Power-law model using only γ data values greater than 100. These where example fluids for demonstrating the Bingham's plastic and Power-law models.

The flow pattern in almost all circumstances is turbulent in the surface equipment and the drill string. Additionally, flow through the bit is based on jet nozzle theory. All published results and CHES agree on the flow pattern in these instances. The difficult decision is determining the onset of turbulent flow or the termination of laminar flow in the annuli. Under most circumstances this decision is very easy as flow will fall into one pattern or the other and the gray area in between is of little concern. However in wellbore hydraulics it is desirable while drilling to be in laminar flow in the annulus and at the same time be flowing fast enough to lift cuttings (and at times even faster than this minimum) so maximum horsepower can be exerted at the bit. When cementing casing strings, turbulent flow in the annulus is needed, so mud is efficiently removed from the wellbore. The expert system employes several methods to determine the flow pattern in the gray area. The results of each method are then given a certainty factor depending upon whether laminar flow (drilling operations) or turbulent flow (cementing operations) is desired.

The frictional pressure losses calculated by the expert system and compared with published results are presented in Table VII. These results are broken down by rheology model and flow pattern. As can be seen the average differences agree very favorably.

CONCLUSIONS

1) Seventeen casing strings designed by manual calculations compare favorably to the expert system's results. Table IV lists the casing string cost by manual calculation and CHES's cost. As can be seen the average difference in cost is 0.13 %. This difference is partially due to the fact that the expert system is able to iterate to a closer tolerance than is reasonable manually.

2) In all cases tested CHES determine the correct sequence of smaller casing size, bit size through which it must pass, and the next larger casing size through which that bit must pass.

3) Six sample fluids from published reports where used as data sets. Tables V and VI shows the values of μ_p, τ_y, n, and K calculated by CHES and the respective sources. The error between CHES's and the sources' equations parameters indicates very close agreement.

4) All published results and CHES agree on the flow pattern in these instances. The frictional pressure losses calculated by the expert system and compared with published results are presented in Table VII. These results are broken down by rheology model and flow pattern. As can be seen the average differences agree very favorably.

5) Bit nozzles sizes determined by CHES agree precisely with calculated sample problems in Bourgoyne et al.

6) The time saved combined with the consistency of results will encourage the drilling engineer to study more "what if" cases than he would have time or energy to if manual calculations were used. This extra time can be spent doing higher level engineering.

7) The author has developed a better understanding of the problems related to nozzle and casing selection. He has also gained an insight into methods to explain these techniques to his future students.

RECOMMENDATIONS

1) As more and more horizontal wells are drilled the information produced will allow additions to CHES that will handle the horizontal well specific cases.

2) Further improvement in CHES will allow petroleum engineering students to use this knowledge base to learn and obtain experience.

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Table I
Turbulent Flow Resistance of Surface Components

		Typical Combinations							
		No.1		No.2		No.3		No.4	
		ID	L	ID	L	ID	L	ID	L
Components	in.	ft.	in.	ft.	in.	ft.	in.	ft.	
Standpipe		3	40	3.5	40	4	45	4	45
Drilling hose	2	45	2.5	55	3	55	3	55	
Swivel		2	4	2.5	5	2.5	5	3	6
Kelly		2.25	40	3.25	50	3.25	40	4	40

Drillpipe

OD in.	Weight lbm/ft.	Equivalent Length of Surface Combinations in Feet of Drillpipe			
3.5	13.3	437	161		
4.5	16.6		761	479	340
5.0	19.5			816	579

Table II
API Specifications for Drill Pipe

OD in.	Weight lbm/ft	Conn. type	ID in.	TJ-ID in.	Equv-ID in.
2.875	6.5	IF	2.441	2.125	2.25
2.875	10.4	XH	2.151	1.875	2.14
2.875	10.4	IF	2.151	2.125	2.15
3.5	13.3	FH-XH	2.764	2.4375	2.74
3.5	13.3	IF	2.764	2.6875	2.76
3.5	15.5	IF	2.602	2.5625	2.6
4	14.	FH	3.34	2.8125	3.29
4	14.	IF	3.34	3.25	3.34
4.5	16.6	FH	3.826	3.	3.76
4.5	16.6	FH-XH	3.826	3.1563	3.78
4.5	16.6	XH	3.826	3.25	3.79
4.5	16.6	IF	3.826	3.75	3.82
4.5	20.	FH-XH	3.64	3.	3.56
4.5	20.	IF	3.64	3.625	3.64
5	19.5	XH	4.276	3.75	4.23
5.5	21.9	REG	4.778	2.75	4.4
5.5	21.9	FH	4.778	3.8125	4.6
5.5	21.9	FH	4.778	4.	4.75
5.5	21.9	IF	4.778	4.8125	4.8
5.5	24.7	FH	4.67	4.	4.6

Table III
API Specifications for Drill Collars

OD in.	Weight lbm/ft.	ID in.
4	36.7	1.5
4	34.5	1.75
4	32.	2.
4	29.2	2.25
4.25	42.2	1.5
4.25	40.	1.75
4.25	37.5	2.
4.25	34.7	2.25
4.5	48.1	1.5
4.5	45.9	1.75
4.5	43.4	2.
4.5	40.6	2.25
4.75	54.3	1.5
4.75	52.1	1.75
4.75	49.6	2.
4.75	46.8	2.25
4.75	43.6	2.5

Table IV
Casing String Costs: Comparison Between Manual Calculations and Expert System

Casing OD (inch)	setting Depth (feet)	Mud Weight (lbm/gal)	Corosive	Manual cost ($)	CHES cost ($)
5.0	13500	11.5	n	141697	141785
5.0	13500	12.0	n	146421	146438
5.0	13500	12.5	n	148372	148232
5.0	13500	13.0	n	150257	150355
5.5	10000	9.8	y	94305	94385
5.5	10000	9.8	n	92194	91969
5.5	10000	10.0	y	95978	95260
5.5	10000	10.0	n	92753	92624
5.5	10000	10.2	y	96558	96135
5.5	10000	10.2	n	93426	93278
5.5	10000	10.7	y	98422	98258
5.5	10000	10.7	n	94851	94744
7.0	6000	8.5	n	68326	68326
7.0	6000	8.7	n	68639	68506
7.0	6000	8.9	n	68795	68676
7.0	6000	9.1	n	68951	68839
7.0	6000	9.3	n	69107	68994
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difference	.13 %			1689051	1686804

Table V
μ_p and τ_y Values for Six Test Fluids

BINGHAM'S PLASTIC fit using all data

FLUID	CHES μ_p *	τ_y @	err	SOURCE μ_p *	τ_y @	
API 10 82	.001663	.1759	.00540	Power-law only		
API 10 87	.000843	.3677	.00460	.00056	.483	
API 13 D	.000641	.0658	.00104	Power-law only		
HOWCO	.001181	.4352	.00015	.00119	.433	$
DOWELL	.000751	.0213	.00000	.00075	.021	$ #
IADC/SPE	.000773	.0676	.00100	Power-law only		

BINGHAM'S PLASTIC fit using gamma > 100 (1/sec)

FLUID	CHES μ_p *	τ_y @	err	SOURCE μ_p *	τ_y @	
API 10 82	.001215	.3256	.00089	Power-law only		
API 10 87	.000544	.4863	.00003	.00056	.483	$
API 13 D	.000559	.1248	.00003	Power-law only		#
HOWCO	.001117	.4596	.00005	.00119	.433	#
DOWELL	.000751	.0213	.00000	.00075	.021	$ #
IADC/SPE	.000694	.1158	.00008	Power-law only		#

* lbf sec / ft^2 [cp = 47900 * (lbf sec / ft^2)] @ lbf / ft^2
# CHES best fit $ best fit with SOURCE

Table VI
n and K Values for Six Test Fluids

POWERLAW fit using all data

FLUID	CHES n *	K @	err	SOURCE n *	K @	
API 10 82	.4203	.06389	.00046	.424	.066	$
API 10 87	.1922	.22504	.00226	Bingham's plastic		
API 13 D	.5756	.01168	.00071	.56	.0119	$
HOWCO	.2480	.19659	.00277	.422	.0810	
DOWELL	.9296	.00124	.00003	Bingham's plastic		
IADC/SPE	.5274	.01671	.00270	.61	.0049	

POWERLAW fit using gamma > 100 (1/sec)

FLUID	CHES n *	K @	err	SOURCE n *	K @	
API 10 82	.4924	.04296	.00026	.424	.066	#
API 10 87	.2524	.15687	.00001	Bingham's plastic		#
API 13 D	.6573	.00709	.00014	.74	.0066	
HOWCO	.3674	.10147	.00033	.422	.0810	
DOWELL	.9296	.00124	.00003	Bingham's plastic		
IADC/SPE	.6616	.00787	.00048	.662	.0057	$

* dimensionless @ lbf sec^n /ft^2
# CHES best fit $ best fit with SOURCE

Table VII

ΔP_d Published versus CHES's Values

SOURCE	q gal/min	ΔP_d psi	ΔP_a * psi	ΔP_p ** psi
HOWCO B[5]	84 @	104.6	72.0	32.6
CHES B	84	110.8	76.2	34.6
HOWCO P	84	103.3	73.2	30.1
CHES P	84	105.4	73.2	32.2
HOWCO B	336 #	123.2	71.8	51.4
CHES B	336	126.7	76.2	50.5
HOWCO P	336	186.4	130.8	55.6
CHES P	336	175.4	122.0	53.4
HOWCO B	630 $	349.6	196.6	153.0
CHES B	663	343.6	193.0	150.6
HOWCO P	663	291.6	170.5	121.1
CHES P	663	261.8	153.8	108.0
HOWCO B	715 &	435.4	244.3	191.1
CHES B	732	445.6	249.7	195.9
HOWCO P	876	446.6	250.9	195.7
CHES P	820	358.6	201.5	157.1

* flow through 1000 ft. of 5 by 7.5 inch annulus
** flow through 1000 ft. of 4.494 inch pipe
ρ = 15.6 lbm/gal, μ_p = 53.5 cp, τ_y = 45.96 lbf/100 ft^2, cement slurry

SOURCE	q gal/min	ΔP_d psi	ΔP_a * psi	ΔP_p ** psi
DOWELL B[6]	228.2 %	155.3	147.6	7.7
CHES B	228.9	156.3	148.5	7.8

* flow through 1500 ft. of 8.5 by 7 inch annulus
** flow through 1500 ft. of 6.184 inch pipe
ρ = 15.6 lbm/gal, μ_p = 36.0 cp, τ_y = 2.13 lbf/100 ft^2, cement slurry

SOURCE	q gal/min	ΔP_d psi	ΔP_a * psi	ΔP_p ** psi
API10 87 B [8]	210 #	109.2	72.9	36.3
CHES B	210	117.3	80.7	36.6
CHES P	210	129.4	87.6	41.8

* flow through 1000 ft. of 8 by 5.5 inch annulus
** flow through 1000 ft. of 4.494 inch pipe
ρ = 14.56 lbm/gal, μ_p = 26.1 cp, τ_y = 48.6 lbm/100 ft^2, n = .2524, K = 7514 equiv. cp, cement slurry

SOURCE	q gal/min	ΔP_d psi	ΔP_a * psi	ΔP_p ** psi
API10 82 P [8]	210 #	325.5	69.5	256.0
CHES P	210	358.0	77.2	280.8

* flow through 1000 ft. of 8 by 5.5 inch annulus
** flow through 1000 ft. of 4.494 inch pipe
ρ = 16.40 lbm/gal, n = 0.4924, K = 3060 equiv. cp, cement slurry

SOURCE	q gal/min	ΔP_d psi	ΔP_a * psi	ΔP_p ** psi
API13D P[4]	280 $	1086	171	915
CHES P	280	1011	158	853
CHES B	280	1100	174	926

SOURCE	ΔP_p ** psi	ΔP_{SE} psi	ΔP_{DP} psi	ΔP_{DC} psi
API13D P	915	0	691	224
CHES P	853	0	644	209
CHES B	926	0	674	252

SOURCE	ΔP_a * psi	$\Delta P_{DC/Bit}$ psi	$\Delta P_{DC/Bit}$ psi	$\Delta P_{DP/Csg}$ psi
API13D P	171	32	108	31
CHES P	158	32	98	28
CHES B	174	29	109	36

* flow through 600 ft. of 8.5 by 6.5 inch, 8400 ft. of 8.5 by 4.5 inch, 3000 ft. of 8.835 by 4.5 inch annuli
** flow through 11400 ft. of 3.78 inch drillpipe and 600 ft. of 2.5 inch drill collars
ρ = 12.50 lbm/gal, n = 0.6573, K = 339.6 equiv. cp, μ_p = 26.8 cp,
τ_y = 12.48 lbm/100 ft^2, drilling mud
P = Power-law model, B = Bingham plastic model
@ annulus plug / laminar flow, pipe laminar flow
\# annulus laminar flow, pipe laminar flow
$ annulus laminar flow, pipe turbulent flow
& annulus laminar / turbulent flow, pipe turbulent flow
% annulus laminar / turbulent flow, pipe laminar flow